UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934
OR
☒ ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2020
Commission file number: 001-37915

FORTIS INC.

(Exact name of Registrant as specified in its charter)

Newfoundland and Labrador, Canada	**4911**	**98-0352146**
(Province of other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

Fortis Place, Suite 1100
5 Springdale Street
St. John's, Newfoundland and Labrador
Canada A1E 0E4

(709) 737-2800
(Address and telephone number of Registrants principal executive offices)

CT Corporation System
28 Liberty Street
New York, New York 10015
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Common Shares, without par value	**FTS**	**New York Stock Exchange**
(Title of each class)	*(Trading Symbol(s))*	*(Name of exchange on which registered)*

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None
(Title of Class)

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

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

466,770,392 Common Shares as of December 31, 2020

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes ☒ No ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

EXPLANATORY NOTE

Fortis Inc. (the "Corporation" or "Fortis") is a Canadian issuer eligible to file its annual report pursuant to Section 13 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), on Form 40-F pursuant to the multi-jurisdictional disclosure system of the Exchange Act. The Corporation is a "foreign private issuer" as defined in Rule 405 under the Securities Act of 1933, as amended. Equity securities of the Corporation are accordingly exempt from Sections 14(a), 14(b), 14(c), 14(f) and 16 of the Exchange Act pursuant to Rule 3a12-3.

FORWARD LOOKING INFORMATION

The Corporation includes forward-looking information in this Annual Report on Form 40-F and the exhibits attached hereto (the "Form 40-F") 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 the Corporation's 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 expressions have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2021-2025 and expected funding sources; the 2035 carbon emissions reduction target; forecast rate base and rate base growth for 2023 and 2025; the expectation that long-term growth in rate base will support earnings and dividend growth; target average annual dividend growth through 2025; the expectation that future increases in energy supply costs will increase electricity rates that Newfoundland Power charges to its customers; TEP's carbon emissions reduction target and projected asset mix; FortisBC's 2030 greenhouse gas emission target and renewable gas target; the expectation that the COVID-19 Pandemic will not have a material financial impact in 2021 and will not impact the five-year capital plan; the expectation that Fortis will remain at the forefront of the industry and is well positioned to capitalize on evolving industry opportunities; expected timing, outcome and impact of regulatory 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 in 2021;

the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Oso Grande Wind Project, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project; Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Resiliency Tank, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan, including the Lake Erie Connector Project; and the expectation that the adoption of future accounting pronouncements will not have a material adverse impact.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: no material adverse effects from the COVID-19 pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the five-year capital plan; no material capital project or financing cost overrun; 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. The Corporation 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 information detailed under the heading "Business Risks" on page 28 of management's discussion and analysis for the year ended December 31, 2020, which is filed as Exhibit 99.3 to this Form 40-F and incorporated by reference herein (the "Annual MD&A"), and to continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission (the "SEC"). Key risk factors for 2021 include, but are not limited to:

- uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities;
- risks associated with climate change, physical risks and service disruption;
- the impact of pandemics and public health crises, including the COVID-19 pandemic;
- risks related to environmental laws and regulations;
- risks associated with capital projects and the impact on the Corporation's continued growth; and
- the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation

All forward-looking information in this Form 40-F is given as of the date of this Form 40-F and the Corporation disclaims any intention or obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

CURRENCY

The Corporation presents its consolidated financial statements in Canadian dollars unless otherwise specified. All dollar amounts in this Form 40-F are stated in Canadian dollars ("$" or "C$"), except where otherwise indicated. On February 11, 2021, the daily average exchange rate (as reported by the Bank of Canada) of United States dollars ("US$") into Canadian dollars was US$1.00 equals C$1.27.

CERTIFICATIONS

See Exhibits 99.4, 99.5, 99.6 and 99.7 to this Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures 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 United States securities laws. As of December 31, 2020, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer, of the effectiveness of the Corporation's disclosure controls and procedures, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer concluded that such disclosure controls and procedures are effective as of December 31, 2020.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Corporation is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer 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 U.S. GAAP. 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.

The Corporation's management, including the Corporation's President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer, assessed the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2020, 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, 2020, the Corporation's internal control over financial reporting was effective.

Deloitte LLP, an independent registered public accounting firm, has audited the Corporation's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2020 filed as Exhibit 99.2 to this Form 40-F (the "Annual Financial Statements"), and has included its attestation report on management’s assessment of the Corporation’s internal control over financial reporting, which is found on page i of the Annual Financial Statements.

ATTESTATION REPORT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Deloitte LLP's attestation report on management’s assessment of the Corporation's internal control over financial reporting is found on page v of the Annual Financial Statements.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Management regularly reviews its system of internal control over financial reporting and makes changes to the Corporation's processes and systems to improve controls and increase efficiency, while ensuring that the Corporation maintains an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

During the year ended December 31, 2020, there have been no changes in the Corporation's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

The Corporation did not send any notices required by Rule 104 of Regulation BTR during the year ended December 31, 2020 concerning any equity security subject to a blackout period under Rule 101 of Regulation BTR.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Corporation has a separately designated standing Audit Committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The Audit Committee is composed of Tracey C. Ball (Chair), Lawrence T. Borgard, Maura J. Clark, Margarita K. Dilley, Douglas J. Haughey and Jo Mark Zurel, as described under "Audit Committee - Members" on page 32 of the Corporation's annual information form for the year ended December 31, 2020, which is filed as Exhibit 99.1 to this Form 40-F and incorporated by reference herein (the "AIF").

AUDIT COMMITTEE FINANCIAL EXPERT

The Board has determined that the Corporation has at least one "audit committee financial expert" (as defined in paragraph (8) of General Instruction B to Form 40-F) and that Tracey C. Ball, Maura J. Clark, Margarita K. Dilley and Jo Mark Zurel are the Corporation's "audit committee financial experts" serving on the Audit Committee of the Board. Each of the audit committee financial experts is "independent" under applicable listing standards.

CODE OF ETHICS

The Corporation has a "code of ethics" (as defined in paragraph (9)(b) of General Instruction B to Form 40-F) that applies to its Chief Executive Officer, Chief Financial Officer, principal accounting officer, controller and persons performing similar functions. The Corporation's code of ethics is available on the Corporation's website at https://www.fortisinc.com/ or, without charge, upon request from the Corporate Secretary, Fortis Inc., Fortis Place, Suite 1100, 5 Springdale Street, St. John's, Newfoundland and Labrador, Canada A1E 0E4 (telephone (709) 737-2800).

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Deloitte LLP served as the Corporation's independent public accountant for the fiscal years ended December 31, 2020 and 2019. For a description of the total amount billed to the Corporation by Deloitte LLP for services performed in the last two fiscal years by category of service (audit fees, audit-related fees, tax fees and all other fees), see "Audit Committee - External Auditor Service Fees" on page 33 of the AIF.

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES

For a description of the pre-approval policies and procedures of the Corporation's Audit Committee, see "Audit Committee - Pre-Approval Policies and Procedures" on page 33 of the AIF.

No audit-related fees, tax fees or other non-audit fees were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

OFF-BALANCE SHEET ARRANGEMENTS

Except for letters of credit outstanding of $130 million as at December 31, 2020 and certain unrecorded commitments disclosed under the heading "Liquidity and Capital Resources - Contractual Obligations" on page 19 of the Annual MD&A, the Corporation has not entered into any "off-balance sheet arrangements", as defined in General Instruction B(11) to Form 40-F, that have or are reasonably likely to have a current or future effect on the Corporation's financial condition, changes in financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For tabular disclosure of the Corporation's contractual obligations, see pag e 22 of the Annual MD&A, under the heading "Liquidity and Capital Resources - Contractual Obligations".

COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

The Corporation is subject to a variety of corporate governance guidelines and requirements enacted by the Toronto Stock Exchange (the "TSX"), the Canadian securities regulatory authorities, the New York Stock Exchange (the "NYSE") and the SEC. The Corporation is listed on the NYSE and, although the Corporation is not required to comply with most of the NYSE corporate governance requirements to which the Corporation would be subject if it were a U.S. corporation, the Corporation's governance practices differ from those required of U.S. domestic issuers only as described herein. The NYSE rules for U.S. domestic issuers require shareholder approval of all equity compensation plans (as defined in the NYSE rules) regardless of whether new issuances, treasury shares or shares that the Corporation has purchased in the open market are used. The TSX rules require shareholder approval of share compensation arrangements involving new issuances of shares, and of certain amendments to such arrangements, but do not require such approval if the compensation arrangements involve only shares purchased in the open market. The NYSE rules for U.S. domestic issuers also require shareholder approval of certain transactions or series of related transactions that result in the issuance of common shares, or securities convertible into or exercisable for common shares, that have, or will have upon issuance, voting power equal to or in excess of 20% of the voting power outstanding prior to the transaction or if the issuance of common shares, or securities convertible into or exercisable for common shares, are, or will be upon issuance, equal to or in excess of 20% of the number of common shares outstanding prior to the transaction. The TSX rules require shareholder approval of acquisition transactions resulting in dilution in excess of 25%. The TSX also has broad general discretion to require shareholder approval in connection with any issuances of listed securities. The Corporation complies with the TSX rules described in this paragraph.

UNDERTAKING

The Corporation undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the SEC staff, and to furnish promptly, when requested to do so by the SEC staff, information relating to: the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

DISCLOSURE PURSUANT TO SECTION 13(r) OF THE EXCHANGE ACT

In accordance with Section 13(r) of the Exchange Act, the Corporation is required to include certain disclosures in its periodic reports if it or any of its affiliates knowingly engaged in certain specified activities during the period covered by the report. Neither the Corporation nor its affiliates have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the year ended December 31, 2020.

INCORPORATION BY REFERENCE

Fortis' Annual Report on Form 40-F (other than the section entitled "Credit Ratings" in Exhibit 99.1 to this Form 40-F) is incorporated by reference into Fortis' Registration Statements on Form S-8 (File No. 333-215777), Form S-8 (File No. 333-226663), Form S-8 (File No. 333-236213), Form F-3 (File No. 333-249039), and Form F-10 (File No. 333-250996).

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form of the Corporation dated February 11, 2021
99.2	Audited Consolidated Financial Statements for the fiscal year ended December 31, 2020
99.3	Management's Discussion and Analysis for the fiscal year ended December 31, 2020
99.4	Chief Executive Officer certification required by Rule 13a-14(a)
99.5	Chief Financial Officer certification required by Rule 13a-14(a)
99.6	Chief Executive Officer certification required by Rule 13a-14(b)
99.7	Chief Financial Officer certification required by Rule 13a-14(b)
99.8	Consent of Deloitte LLP
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Corporation certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

FORTIS INC.

/s/ Jocelyn H. Perry

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer
Date: February 12, 2021

Exhibit 99.1



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2020

February 11, 2021

ANNUAL INFORMATION FORM

For the year ended December 31, 2020
Dated February 11, 2021

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Financial information in this AIF has been prepared in accordance with US GAAP and is presented in Canadian dollars ($) based, as applicable, on the following US-to-Canadian dollar exchange rates: (i) average of 1.34 and 1.33 for the years ended December 31, 2020 and 2019, respectively; (ii) 1.27 and 1.30 as at December 31, 2020 and 2019, respectively; and (iii) 1.32 for all forecast periods.

Except as otherwise expressly noted, the information in this AIF is given as of December 31, 2020.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in this AIF 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: forecast capital expenditures for 2021-2025; the 2035 carbon emissions reduction target; forecast rate base for 2023 and 2025; additional opportunities beyond the capital plan; the expectation that long-term growth in rate base will support earnings and dividend growth; target average annual dividend growth through 2025; the expectation that future increases in energy supply costs will increase electricity rates that Newfoundland Power charges to its customers; TEP's carbon emissions reduction target and projected asset mix; and FortisBC's 2030 GHG emission target and renewable gas target.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: no material adverse effects from the COVID-19 pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project or financing cost overrun; sufficient human resources to deliver service and execute the capital plan; no significant variability in interest rates; the Board exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; 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.

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 in the MD&A under the heading "Business Risks" and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission.

All forward-looking information in this AIF is given as of the date of this AIF. 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

Certain terms used in this 2020 Annual Information Form are defined below:

2020 Annual Information Form or **AIF:** this annual information form of the Corporation in respect of the year ended December 31, 2020

ACGS: Aitken Creek Gas Storage ULC

Aitken Creek: Aitken Creek natural gas storage facility

Algoma Power: Algoma Power Inc.

APS: Arizona Public Service Company

AUC: Alberta Utilities Commission

BC Hydro: BC Hydro and Power Authority

BCUC: British Columbia Utilities Commission

BECOL: Belize Electric Company Limited

Belize Electricity: Belize Electricity Limited

Board: Board of Directors of the Corporation

Canadian Niagara Power: Canadian Niagara Power Inc.

CUPE: Canadian Union of Public Employees

Caribbean Utilities: Caribbean Utilities Company, Ltd.

CBT: Columbia Basin Trust

Central Hudson: Central Hudson Gas & Electric Corporation

CMS: Consumers Energy Company

Cornwall Electric: Cornwall Street Railway, Light and Power Company, Limited

Corporation: Fortis Inc.

CPA: Canal Plant Agreement

CPC: Columbia Power Corporation

DBRS Morningstar: DBRS Limited

DTE: DTE Electric Company

EDGAR: SEC's system for Electronic Data Gathering, Analysis and Retrieval available at www.sec.gov

Eiffel Investment: Eiffel Investment Pte Ltd.

FERC: Federal Energy Regulatory Commission

FHI: FortisBC Holdings Inc.

Financial Statements: the Corporation's Audited Consolidated Financial Statements in respect of the year ended December 31, 2020

Fitch: Fitch Ratings Inc.

Fortis: Fortis Inc.

FortisAlberta: FortisAlberta Inc.

FortisBC Electric: collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc.

FortisBC Energy: FortisBC Energy Inc.

FortisOntario: FortisOntario Inc.

FortisTCI: collectively, FortisTCI Limited and Turks and Caicos Utilities Limited

FortisUS: FortisUS Inc.

FortisUS Holdings: FortisUS Holdings Nova Scotia Limited

FortisWest: FortisWest Inc.

GHG: greenhouse gas

GIC: GIC Private Limited

GSMIP: Gas Supply Mitigation Incentive Plan of FortisBC Energy

IBEW: International Brotherhood of Electrical Workers

IESO: Independent Electricity System Operator of Ontario

IPL: Interstate Power and Light Company

ITC: ITC Holdings together with all of its subsidiaries

ITC Great Plains: ITC Great Plains, LLC

ITC Holdings: ITC Holdings Corp.

ITC Interconnection: ITC Interconnection LLC

ITC Investment Holdings: ITC Investment Holdings Inc.

ITC Midwest: ITC Midwest LLC

ITC's MISO Regulated Operating Subsidiaries: collectively ITCTransmission, METC and ITC Midwest

ITC's Regulated Operating Subsidiaries: collectively, ITCTransmission, METC, ITC Midwest, ITC Great Plains and ITC Interconnection

ITCTransmission: International Transmission Company

LNG: liquefied natural gas

Maritime Electric: Maritime Electric Company, Limited

MD&A: the Corporation's Management Discussion and Analysis in respect of the year ended December 31, 2020

METC: Michigan Electric Transmission Company

MISO: Midcontinent Independent System Operator, Inc.

Moody's: Moody's Investors Service, Inc.

MoveUP: Movement of United Professionals

NB Power: New Brunswick Power Corporation

Newfoundland Power: Newfoundland Power Inc.

NL Hydro: Newfoundland and Labrador Hydro Corporation

NYPSC: New York Public Service Commission

NYSE: New York Stock Exchange

PEI: the province of Prince Edward Island, Canada

PNM: Public Service Company of New Mexico

PPA: power purchase agreement

PUB: Newfoundland and Labrador Board of Commissioners of Public Utilities

PWU: Power Workers' Union

ROE: return on common equity

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

SEC: United States Securities and Exchange Commission

SEDAR: the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators available at www.sedar.com

SPP: Southwest Power Pool, Inc.

SRP: Salt River Project Agricultural Improvement and Power District

T&D: transmission and distribution

TC Energy: TC Energy Corporation

TEP: Tucson Electric Power Company

TSX: Toronto Stock Exchange

UNS Electric and **UNSE:** UNS Electric, Inc.

UNS Energy: UNS Energy Corporation

UNS Gas: UNS Gas, Inc.

US: United States of America

US GAAP: accounting principles general accepted in the US

UUWA: United Utility Workers' Association of Canada

Waneta Expansion: 335-MW Waneta Expansion hydroelectric generating facility

Wataynikaneyap Partnership: Wataynikaneyap Power Limited Partnership

Measurements:
GW Gigawatt(s)
GWh Gigawatt hour(s)
km Kilometre(s)
MW Megawatt(s)
TJ Terajoule(s)
PJ Petajoule(s)

Conversions:
1 litre = 0.22 imperial gallons
1 kilometre = 0.62 miles

Conversion using the above factors on rounded numbers appearing in this AIF may produce small differences from reported amounts as a result.

CORPORATE STRUCTURE

Name and Incorporation

Fortis Inc. is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987. The corporate head office and registered office of Fortis is located at Fortis Place, Suite 1100, 5 Springdale Street, P.O. Box 8837, St. John's, Newfoundland and Labrador, Canada, A1B 3T2.

The articles of continuance of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the common shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012; (xiii) designate 12,000,000 First Preference Shares, Series K and 12,000,000 First Preference Shares, Series L on July 11, 2013; and; (xiv) designate 24,000,000 First Preference Shares, Series M and 24,000,000 First Preference Shares, Series N on September 16, 2014.

Inter-Corporate Relationships

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at February 11, 2021. The principal subsidiaries together comprise approximately 89% of the Corporation's consolidated assets as at December 31, 2020 and approximately 86% of the Corporation's 2020 consolidated revenue. This table excludes certain subsidiaries, the assets and revenues of which did not individually exceed 10%, or in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2020.

Subsidiary	Jurisdiction of Incorporation	Votes attaching to voting securities beneficially owned, controlled or directed by the Corporation *(%)*
ITC [(1)]	Michigan, United States	80.1
UNS Energy [(2)]	Arizona, United States	100
Central Hudson [(3)]	New York, United States	100
FortisBC Energy [(4)]	British Columbia, Canada	100
FortisAlberta [(5)]	Alberta, Canada	100
Newfoundland Power [(6)]	Newfoundland and Labrador, Canada	100

(1) *ITC Holdings, a Michigan corporation, owns all of the shares of ITC Great Plains, ITC Interconnection, ITC Midwest, ITCTransmission and METC. ITC Investment Holdings, a Michigan corporation, owns all of the shares of ITC Holdings. FortisUS, a Delaware corporation, owns 80.1% of the voting securities of ITC Investment Holdings. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings. 19.9% of the voting securities of ITC Investment Holdings are owned by an affiliate of GIC.*

(2) *UNS Energy owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS owns all of the shares of UNS Energy.*

(3) *CH Energy Group, Inc., a New York corporation, owns all of the shares of Central Hudson. FortisUS owns all of the shares of CH Energy Group, Inc.*

(4) *FHI, a British Columbia corporation, owns all of the shares of FortisBC Energy. Fortis owns all of the shares of FHI.*

(5) *FortisAlberta Holdings Inc., an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings Inc. Fortis owns all of the shares of FortisWest.*

(6) *Fortis owns all of the shares of Newfoundland Power.*

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Fortis is a well-diversified leader in the North American regulated electric and gas utility industry, with 2020 revenue of $8.9 billion and total assets of $55 billion as at December 31, 2020.

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, 2020, 66% of the Corporation's assets were located outside Canada and 59% of 2020 revenue was derived from foreign operations.

Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have increased from $47.8 billion at the start of 2018 to $55.5 billion as at December 31, 2020. The Corporation's shareholders' equity has also grown from $16.7 billion at the start of 2018 to $20.3 billion as at December 31, 2020. Net earnings attributable to common equity shareholders have increased from $1,100 million in 2018 to $1,209 million in 2020.

The growth in business operations reflects the Corporation's organic growth strategy for its principal regulated utilities.

2018
In 2018 the Corporation deployed capital expenditures of $3.2 billion at its utilities and announced an ambitious utility capital plan of $17.3 billion for the period 2019 to 2023, an increase of 20% over the prior year's plan. The increase in annual earnings for 2018 was driven by growth at both the regulated and non-regulated businesses, as well as lower income tax expense primarily related to a one-time expense in 2017 associated with US tax reform, along with the positive tax impacts of electing to file a consolidated state tax return and designating assets as "held for sale" in 2018.

2019
In January 2019 Fortis announced that it entered into a definitive agreement with CBT and CPC to sell its 51% interest in the Waneta Expansion for approximately $1 billion. The transaction closed in April 2019. The sale of the Corporation's interest in the Waneta Expansion completed the asset sale portion of the Corporation's capital funding strategy.

In September 2019 Fortis announced its five-year capital plan of $18.8 billion for the period 2020 to 2024. The Corporation deployed capital expenditures of $3.8 billion at its utilities in 2019.

2020
Fortis performed well as it navigated through the global COVID-19 pandemic throughout 2020. Approximately half of the Corporation's employees transitioned to working from home while field operation employees adapted to work safely to maintain the Corporation's critical infrastructure and continue to deliver essential energy to customers.

In September 2020 the Corporation announced a five-year capital plan of $19.6 billion for the period 2021 to 2025. This plan represents an increase in $800 million from the prior year's plan. The capital plan focuses on a diverse mix of low-risk, highly executable projects needed to maintain and upgrade our existing infrastructure to expand capacity, improve reliability and support a cleaner energy future.

Also in September 2020 the Corporation announced it is building on its low emissions profile by establishing a corporate-wide target to reduce carbon emissions by 75% by 2035 from a 2019 base year. Fortis expects to achieve the target through delivering on planned carbon emissions reductions at TEP as well as clean energy initiatives across the Corporation's other utilities. For details on the Corporation's carbon emissions reduction target, refer to the "Sustainability" section of this AIF.

Barry V. Perry, President and Chief Executive Officer of Fortis, retired from Fortis at the end of 2020 after a nearly 35-year career, over 20 of which were with Fortis. David G. Hutchens, formerly Chief Operating Officer of Fortis and Chief Executive Officer of UNS Energy, was appointed as Mr. Perry's successor and a member of the Board effective January 1, 2021.

In addition to the efforts across the Fortis group to control costs during the pandemic, the Corporation's utilities have regulatory mechanisms that help stabilize cash flow and earnings which support the continued delivery of reliable service. Approximately 83% of the Corporation's revenues are either protected by regulatory mechanisms or are derived from residential sales which have generally increased as a result of work-from-home practices.

Excluding the impact of the delay in TEP's general rate application, the COVID-19 pandemic did not have a material impact on the Corporation's capital expenditures, revenue or earnings in 2020. The financial impact to Fortis approximated $0.05 per common share, reflecting reduced sales in the Caribbean and higher net operational expenses, including an increase in credit loss expense, largely at Central Hudson and UNS Energy.

Net earnings attributable to common equity shareholders for 2020 were $1,209 million compared to $1,655 million for 2019. The decrease included (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the November 2019 and May 2020 FERC decisions at ITC.

The Corporation executed its largest capital plan on record in 2020, with consolidated capital expenditures of $4.2 billion. Despite adjustments to work practices and the necessary rescheduling of certain field work due to the COVID-19 pandemic, work remained on track and the Corporation delivered its strongest safety results in its history.

Over the past three years, including 2020, consolidated capital expenditures totalled $11.2 billion. Organic asset growth has been driven by capital expenditures at the Corporation's regulated utilities.

Outlook

The Corporation maintains its positive long-term outlook. Fortis continues 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. While uncertainty exists due to the COVID-19 pandemic, the Corporation does not currently expect it to have a material financial impact in 2021.

The Corporation's $19.6 billion five-year capital plan is expected to increase rate base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, translating into three- and five-year compound annual growth rates of approximately 6.5% and 6.0%, respectively. Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities, including: 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 infrastructure investments across our jurisdictions.

Fortis expects long-term growth in rate base will support earnings and dividend growth. Fortis is targeting average annual dividend growth of approximately 6% through 2025.

DESCRIPTION OF THE BUSINESS

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. Earnings, earnings per share and total shareholder return are the primary measures of financial performance.

The Corporation's 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 consists of Aitken Creek (natural gas storage facility - British Columbia), BECOL (three hydroelectric generation facilities with a combined capacity of 51 MW - Belize) and the Waneta Expansion up to its disposition in April 2019.

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 its capital plan and the pursuit of investment opportunities within and proximate to its service territories.

Competition

Most of the Corporation's regulated utilities operate as the sole supplier of electricity and/or gas within their respective service territories. Competition in the regulated electric business is primarily from alternative energy sources and on-site generation by industrial customers. The Corporation faces competition in its transmission business which may restrict its ability to grow this business outside of its established service territories.

At the Corporation's regulated gas utilities, natural gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital cost differences between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a fully costed basis. Government policy could also impact the competitiveness of natural gas in the Corporation's service territories. The British Columbia provincial government has introduced changes to energy policy, including GHG emission reduction targets and a tax on carbon-based fuels which is expected to increase in the future. As all levels of government become more active in the development of policies to address climate change, any resultant 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.

Seasonality

As the Corporation's subsidiaries operate in various jurisdictions throughout North America, seasonality impacts each utility differently. Most of the annual earnings of the Corporation's gas utilities are realized in the first and fourth quarters due to space heating requirements in colder weather. Earnings for electric utilities in the US are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment in the summer.

Summary of Operations

The following table and sections describe the Corporation's operations and reportable segments.

	Customers	Peak Demand [1]	Electric T&D Lines *(circuit km)*	Gas T&D Lines *(km)*	Generating Capacity *(MW)*	Revenue *($ millions)*	GWh Sales	Gas Volumes *(PJ)*	Employees
Regulated Utilities									
ITC	—	23,364 MW	25,800	—	—	1,744	—	—	699
UNS Energy	694,000	3,309 MW	22,700	5,100	3,233	2,260	16,763	15	2,057
		107 TJ							
Central Hudson	380,000	1,142 MW	15,100	2,400	65	953	4,969	23	1,061
		121 TJ							
FortisBC Energy	1,048,000	1,555 TJ	—	49,500	—	1,385	—	219	1,954
FortisAlberta	572,000	2,770 MW	91,000	—	—	596	16,092	—	1,085
FortisBC Electric	182,000	740 MW	7,300	—	225	424	3,291	—	560
Other Electric									
Newfoundland Power	270,000	1,356 MW	12,500	—	143	717	5,729	—	613
Maritime Electric	84,000	287 MW	6,300	—	130	219	1,293	—	200
FortisOntario	67,000	258 MW	3,500	—	5	225	1,289	—	213
Caribbean Utilities	31,000	109 MW	800	—	161	243	644	—	228
FortisTCI	15,000	40 MW	700	—	91	81	220	—	168
Non-Regulated									
Energy Infrastructure	—	—	—	—	51	88	229	—	68
Corporate and Other	—	—	—	—	—	—	—	—	55
Total	3,343,000	33,375 MW	185,700	57,000	4,104	8,935	50,519	257	8,961
		1,783 TJ							

[1] *Electric (MW) or gas (TJ)*

Regulated Utilities

ITC

ITC's business consists mainly of the electric transmission operations. ITC's Regulated Operating Subsidiaries own and operate high-voltage electric transmission systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to ITC's transmission systems. ITC's business strategy is to own, operate, maintain and invest in transmission infrastructure in order to enhance system integrity and reliability, reduce transmission constraints and support new generating resources interconnecting to ITC's transmission system.

ITC's Regulated Operating Subsidiaries earn revenues from the use of their transmission systems by customers, including investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, ITC's Regulated Operating Subsidiaries are subject to rate regulation by FERC. The rates charged are established using cost-based formula rates.

ITC's principal transmission service customers are DTE, CMS and IPL. One or more of these customers together have consistently represented a significant percentage of ITC's operating revenue. Nearly all of ITC's revenues are from transmission customers in the US.

Market and Sales

Revenues

Revenue was $1,744 million in 2020 compared to $1,761 million in 2019.

ITC derives nearly all of its revenues from transmission, scheduling, control and dispatch services and other related services over ITC's Regulated Operating Subsidiaries' transmission systems to DTE, CMS, IPL and other entities, such as alternative energy suppliers, power marketers and other wholesale customers that provide electricity to end-use customers, as well as from transaction-based capacity reservations on ITC's transmission systems. MISO and SPP are responsible for billing and collecting the majority of transmission service revenues. As the billing agents for ITC's MISO Regulated Operating Subsidiaries and ITC Great Plains, MISO and SPP collect fees for the use of ITC's transmission systems, invoicing DTE, CMS, IPL and other customers on a monthly basis.

The following table compares the composition of ITC's 2020 and 2019 revenue by customer class.

	Revenue *(%)*	
	2020	2019
Network revenues	**65.6**	63.0
Regional cost-sharing revenues	**27.9**	27.9
Point-to-point	**1.0**	1.0
Scheduling, control and dispatch	**1.6**	1.3
Recognition of ROE complaint liabilities[(1)]	**2.4**	5.2
Other	**1.5**	1.6
Total	**100.0**	100.0

(1) *Adjustments have been made to the refund liability recorded related to the complaint proceedings on the MISO base rate of return on equity, which resulted in increases in operating revenues for the periods presented.*

Network revenues are generated from network customers for their use of ITC's electric transmission systems and are based on the actual revenue requirements as a result of ITC's accounting under its cost-based formula rates that contain a true-up mechanism.

Network revenues from ITC Great Plains include the annual revenue requirements specific to projects that are charged exclusively within one pricing zone within SPP or are classified as direct assigned network upgrades under the SPP tariff and contain a true-up mechanism.

Regional cost-sharing revenues are generated from transmission customers for their use of ITC's MISO Regulated Operating Subsidiaries' network upgrade projects that are eligible for regional cost-sharing under provisions of the MISO tariff, including multi-value projects, which have been determined by MISO to have regional value while meeting near-term needs. Additionally, certain projects at ITC Great Plains are eligible for recovery through a region-wide charge under provisions of the SPP tariff. Regional cost sharing revenues are treated as a revenue credit to regional or network customers and is a reduction to gross revenue requirement when calculating net revenue requirement under ITC's cost-based formula rates.

Point-to-point revenues consist of revenues generated from a type of transmission service for which the customer pays for transmission capacity reserved along a specified path between two points on an hourly, daily, weekly or monthly basis. Point-to-point revenues also include other components pursuant to schedules under the MISO and SPP tariffs. Point-to-point revenues are treated as a revenue credit to network or regional customers and are a reduction to gross revenue requirement when calculating net revenue requirement under ITC's cost-based formula rates.

Scheduling, control and dispatch revenues are allocated to ITC's MISO Regulated Operating Subsidiaries by MISO as compensation for the services performed in operating the transmission system. Such services include monitoring of reliability data, current and next-day analysis, implementation of emergency procedures and outage coordination and switching.

Other revenues consist of rental revenues, easement revenues, revenues relating to utilization of jointly-owned assets under ITC's transmission ownership and operating agreements and amounts from providing ancillary services to customers. The majority of other revenues are treated as a revenue credit and taken as a reduction to gross revenue requirements when calculating the net revenue requirement under ITC's cost-based formula rates.

Contracts

ITCTransmission

DTE operates an electric distribution system that is interconnected with ITCTransmission's transmission system. A set of three operating contracts sets forth the terms and conditions related to DTE's and ITCTransmission's ongoing working relationship. These contracts include:

Master Operating Agreement - governs the primary day-to-day operational responsibilities of ITCTransmission and DTE. It identifies the control area coordination services that ITCTransmission is obligated to provide to DTE and certain generation-based support services that DTE is required to provide to ITCTransmission.

Generator Interconnection and Operation Agreement - established, re-established and maintains the direct electricity interconnection of DTE's electricity generating assets with ITCTransmission's transmission system for the purposes of transmitting electric power from and to the electricity generating facilities.

Coordination and Interconnection Agreement - governs the rights, obligations and responsibilities of ITCTransmission and DTE regarding, among other things, the operation and interconnection of DTE's distribution system and ITCTransmission's transmission system, and the construction of new facilities or modification of existing facilities. Additionally, this agreement allocates costs for operation of supervisory, communications and metering equipment.

METC

CMS operates an electric distribution system that interconnects with METC's transmission system. METC is a party to a number of operating contracts with CMS that govern the operations and maintenance of its transmission system. These contracts include:

Amended and Restated Easement Agreement - CMS provides METC with an easement to the land on which a majority of METC's transmission towers, poles, lines and other transmission facilities, used to transmit electricity for CMS and others, are located. METC pays CMS a nominal annual rent for the easement and also pays for any rentals, property taxes and other fees related to the property covered by the agreement.

Amended and Restated Operating Agreement - METC is responsible for maintaining and operating its transmission system, providing CMS with information and access to its transmission system and related books and records, administering and performing the duties of control area operator (that is, the entity exercising operational control over the transmission system) and, if requested by CMS, building connection facilities necessary to permit interaction with new distribution facilities built by CMS.

Amended and Restated Purchase and Sale Agreement for Ancillary Services -Since METC does not own any generating facilities, it must procure ancillary services from third-party suppliers, such as CMS. Currently, under this agreement, METC pays CMS for providing certain generation-based services necessary to support the reliable operation of the bulk power grid, such as voltage support and generation capability and capacity to balance loads and generation.

Amended and Restated Distribution-Transmission Interconnection Agreement - provides for the interconnection of CMS's distribution system with METC's transmission system and defines the continuing rights, responsibilities and obligations of the parties with respect to the use of certain of their own and the other parties' property, assets and facilities.

Amended and Restated Generator Interconnection Agreement -specifies the terms and conditions under which CMS and METC maintain the interconnection of CMS's generation resources and METC's transmission assets.

ITC Midwest

IPL operates an electric distribution system that interconnects with ITC Midwest's transmission system. ITC Midwest is a party to a number of operating contracts with IPL that govern the operations and maintenance of its transmission system. These contracts include:

Distribution-Transmission Interconnection Agreement - governs the rights, responsibilities and obligations of ITC Midwest and IPL, with respect to the use of certain of their own and the other party's property, assets and facilities and the construction of new facilities or modification of existing facilities.

Large Generator Interconnection Agreement - ITC Midwest, IPL and MISO entered into this agreement in order to establish, re-establish and maintain the direct electricity interconnection of IPL's electricity generating assets with ITC Midwest's transmission system for the purposes of transmitting electric power from and to the electricity generating facilities.

UNS Energy

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona. It is engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 694,000 electricity and gas customers. UNS Energy primarily consists of three wholly owned regulated utilities: TEP, UNS Electric and UNS Gas.

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility that generates, transmits and distributes electricity. TEP serves approximately 433,000 retail customers in a territory comprising approximately 2,991 square km in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP's service area covers a population of over one million people. TEP also sells wholesale electricity to other entities in the western US.

UNS Electric is a vertically integrated regulated electric utility that generates, transmits and distributes electricity to approximately 98,000 retail customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric own generation resources with an aggregate capacity of 3,233 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2020, approximately 33% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility that serves approximately 163,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Market and Sales

UNS Energy's electricity sales were 16,763 GWh in 2020, compared to 18,354 GWh in 2019. Gas volumes were 15 PJ in 2020 compared to 16 PJ in 2019. Revenue was $2,260 million in 2020, compared to $2,212 million in 2019.

The following table provides the composition of UNS Energy's 2020 and 2019 revenue, electricity sales, and gas volumes by customer class.

	Revenue *(%)*		**GWh Sales** *(%)*		**PJ Volumes** *(%)*	
	2020	2019	**2020**	2019	**2020**	2019
Residential	**40.9**	36.5	**30.9**	25.0	**57.3**	57.9
Commercial	**20.9**	21.2	**16.1**	15.1	**22.1**	23.4
Industrial	**13.8**	13.8	**18.0**	16.6	**1.9**	2.0
Other [(1)]	**24.4**	28.5	**35.0**	43.3	**18.7**	16.7
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes electricity sales and gas volumes to other entities for resale and revenue from sources other than from the sale of electricity and gas*

Power Supply

TEP meets the electricity supply requirements of its retail and wholesale customers with its owned electrical generating capacity of 2,932 and its T&D system consisting of approximately 16,000 km of line. In 2020 TEP met a peak demand of 2,812 MW, which includes firm sales to wholesale customers. TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities.

TEP's generating capacity is set forth in the following table.

Generation Source	Unit No.	Location	Date in Service	Total Capacity *(MW)*	Operating Agent	TEP's Share *(%)*	TEP's Share *(MW)*
Coal							
Springerville Station	1	Springerville, AZ	1985	387	TEP	100.0	387
Springerville Station [1]	2	Springerville, AZ	1990	406	TEP	100.0	406
San Juan Station	1	Farmington, NM	1976	340	PNM	50.0	170
Four Corners Station	4	Farmington, NM	1969	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	785	APS	7.0	55
Natural Gas							
Gila River Power Station	2	Gila Bend, AZ	2003	550	SRP	100.0	550
Gila River Power Station [2]	3	Gila Bend, AZ	2003	550	SRP	75.0	413
Luna Generating Station	1	Deming, NM	2006	555	PNM	33.3	185
Sundt Station	3	Tucson, AZ	1962	104	TEP	100.0	104
Sundt Station	4	Tucson, AZ	1967	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	50	TEP	100.0	50
Sundt Reciprocating Internal Combustion Engine [3]	1-10	Tucson, AZ	2019-2020	188	TEP	100.0	188
DeMoss Petrie	N/A	Tucson, AZ	2001	75	TEP	100.0	75
North Loop	N/A	Tucson, AZ	2001	96	TEP	100.0	96
Solar							
Utility-Scale Renewables [4]		Various	2002-2017	42	TEP	100.0	42
Total Capacity							**2,932**

(1) *Springerville Generating Station Unit 2 is owned by San Carlos Resources Inc., a wholly owned subsidiary of TEP.*
(2) *TEP owns 75% of Gila River Unit 3 and UNSE owns 25%.*
(3) *TEP placed in service five natural gas reciprocating internal combustion engine units in December 2019 and an additional five units in March 2020.*
(4) *In September 2020, Sundt Areva Solar Thermal, with a nominal capacity of 5 MW, was retired.*

UNS Electric meets the electricity supply requirements of its retail customers with its owned electrical generating capacity of 302 MW and purchasing power on the wholesale market, and its T&D system consisting of approximately 7,000 km of line. In 2020 UNS Electric met a peak demand of 497 MW.

UNS Electric's generating capacity is set forth in the following table.

Generation Source	Unit No.	Location	Date In Service	Resource Type	Total Capacity *(MW)*	Operating Agent	UNSE's Share *(%)*	UNSE's Share *(MW)*
Black Mountain	1	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Black Mountain	2	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Valencia	1	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	2	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	3	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	4	Nogales, AZ	2006	Gas/Oil	21	UNSE	100.0	21
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	SRP	25.0	137
Utility-Scale Renewables	N/A	Various	2011 -2017	Solar	12	UNSE	100.0	12
Total Capacity								**302**

Owned Utility-Scale Renewable Resources

TEP owns 42 MW of photovoltaic solar generation capacity and has 260 MW of renewable resources under development that are expected to be placed into service in 2021. The Oso Grande Wind Project will add approximately 250 MW of wind-powered electric generation and Raptor Ridge will add 10 MW of solar-powered electric generation. UNS Electric owns 12 MW of photovoltaic solar generation capacity.

Renewable Power Purchase Agreements

TEP has renewable PPAs of 156 MW from solar resources and 80 MW from wind resources. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future date. Wilmot Solar is under development and will add 100 MW from solar resources to TEP's capacity, accompanied by 30 MW of energy storage. Wilmot Solar is expected to be placed into service in 2021. Borderlands Wind is under development and will add 99 MW from wind resources and is expected to be placed into service in 2021. UNS Electric has renewable PPAs of 83 MW from solar resources and 10 MW from wind resources.

Gas Purchases

TEP and UNS Gas directly manage their gas supply and transportation contracts. The price for gas varies based on market conditions, which include weather, supply balance, economic growth rates and other factors. TEP and UNS Gas hedge their gas supply prices by entering into fixed-price forward contracts, collars, and financial swaps from time to time, up to three years in advance, with a view to hedging at least 70-90% of expected monthly energy volumes prior to the beginning of each month.

Central Hudson

Central Hudson is a regulated electric and gas T&D utility serving approximately 300,000 electricity customers and 80,000 natural gas customers in portions of New York State's Mid-Hudson River Valley. Central Hudson serves a territory comprising approximately 6,700 square km in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and around the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric T&D system consists of approximately 15,100 circuit km of line and met a peak demand of 1,142 MW in 2020.

Central Hudson's natural gas system consists of approximately 2,400 km of T&D pipelines and met a peak day demand of 121 TJ in 2020.

Market and Sales

Central Hudson's electricity sales were 4,969 GWh in 2020, compared to 4,963 GWh in 2019. Natural gas sales volumes in 2020 were 23 PJ, compared to 22 PJ in 2019. Revenue was $953 million in 2020, compared to $917 million in 2019.

The following table compares the composition of Central Hudson's 2020 and 2019 revenue, electricity sales and gas volumes by customer class.

	Revenue *(%)*		**GWh Sales** *(%)*		**PJ Volumes** *(%)*	
	2020	2019	**2020**	2019	**2020**	2019
Residential	**63.3**	62.5	**44.6**	41.4	**25.5**	28.8
Commercial	**26.9**	27.8	**35.9**	38.9	**34.1**	38.8
Industrial	**4.3**	3.9	**17.9**	18.1	**14.2**	16.9
Other [(1)]	**5.5**	5.8	**1.6**	1.6	**26.2**	15.5
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

(1) *Includes sales for resale*

Power Supply

Central Hudson relies on purchased capacity and energy from third-party providers, together with its own minimal generating capacity, to meet the demands of its full-service customers.

Central Hudson is obligated to supply electricity to its retail electric customers. Central Hudson, the staff of the NYPSC and others entered into a settlement agreement in 1998 with respect to the auction of fossil fuel generation plants owned by Central Hudson. Under the settlement agreement, Central Hudson's retail customers may elect to procure electricity from third-party suppliers or may continue to rely on Central Hudson. As part of its requirement to supply customers who continue to rely on Central Hudson for their energy supply, Central Hudson entered into a 10-year revenue sharing agreement with Constellation Energy Group, Inc. in 2011, pursuant to which Central Hudson shares in a portion of the power sales revenue attributable to Unit No. 2 of the Nine Mile Point Nuclear Generating Station.

Costs of electric and natural gas commodity purchases are recovered from customers, without earning a profit on these costs. Rates are reset monthly based on Central Hudson's actual costs to purchase the electricity and natural gas needed to serve its full-service customers.

FortisBC Energy

FortisBC Energy is the largest distributor of natural gas in British Columbia, serving approximately 1,048,000 customers in more than 135 communities. FortisBC Energy provides T&D services to customers, and obtains natural gas supplies on behalf of most of its residential, commercial and industrial customers. FortisBC Energy owns and operates approximately 49,500 km of natural gas pipelines and met a peak demand of 1,555 TJ in 2020.

Market and Sales

FortisBC Energy's natural gas sales volumes were 219 PJ in 2020, compared to 227 PJ in 2019. Revenue was $1,385 million in 2020 compared to $1,331 million in 2019.

The following table compares the composition of FortisBC Energy's 2020 and 2019 revenue and natural gas volumes by customer class.

	Revenue *(%)*		**PJ Volumes** *(%)*	
	2020	2019	**2020**	2019
Residential	**57.4**	57.7	**37.2**	35.7
Commercial	**28.7**	28.6	**24.6**	22.9
Industrial	**6.7**	4.3	**7.8**	4.4
Other [(1)]	**7.2**	9.4	**30.4**	37.0
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue and gas volumes from transportation customers*

Gas Purchase Agreements

To ensure supply of adequate resources for reliable natural gas deliveries to its customers, FortisBC Energy purchases natural gas supply from counterparties, including producers, aggregators and marketers. FortisBC Energy contracts for approximately 184 PJ of baseload and seasonal supply, of which the majority is sourced in northeast British Columbia and transported on Westcoast Energy Inc.'s T-South pipeline system. The remainder is sourced in Alberta and transported on TC Energy's pipeline transportation system.

FortisBC Energy procures and delivers natural gas directly to core market customers. Transportation customers are responsible to procure and deliver their own natural gas to the FortisBC Energy system and FortisBC Energy then delivers the gas to the operating premises of these customers. FortisBC Energy contracts for transportation capacity on third-party pipelines, such as the T-South pipeline and the TC Energy pipeline, to transport gas supply from various market hubs to FortisBC Energy's system. These third-party pipelines are regulated by the Canada Energy Regulator. FortisBC Energy pays both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by FortisBC Energy's core market customers. FortisBC Energy contracts for firm transportation capacity to ensure it is able to meet its obligation to supply customers within its broad operating region under all reasonable demand scenarios.

Gas Storage and Peak Shaving Arrangements

FortisBC Energy incorporates peak shaving and gas storage facilities into its portfolio to: (i) supplement contracted baseload and seasonal gas supply in the winter months, while injecting excess baseload supply to refill storage in the summer months; (ii) mitigate the risk of supply shortages during cooler weather and peak demand; (iii) manage the cost of gas during the winter months; and (iv) balance daily supply and demand on the distribution system during periods of peak use that occur during the winter months.

FortisBC Energy holds approximately 36 PJs of total storage capacity. FortisBC Energy owns Tilbury and Mount Hayes LNG peak shaving facilities, which provide on-system storage capacity and deliverability. FortisBC Energy also contracts for underground storage capacity and deliverability from parties in northeast British Columbia, Alberta and the Pacific Northwest of the US. On a combined basis, FortisBC Energy's Tilbury and Mount Hayes facilities, the contracted storage facilities, and other peaking arrangements can deliver up to 0.85 PJs per day of supply to FortisBC Energy on the coldest days of the heating season. The heating season typically occurs during the period from December to February.

Mitigation Activities

FortisBC Energy engages in off-system sales activities that allow for the recovery or mitigation of costs of any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met.

Under the GSMIP revenue sharing model, which is approved by the BCUC, FortisBC Energy can earn an incentive payment for mitigation activities. Historically, FortisBC Energy has earned approximately $1.8 million annually through GSMIP, while the remaining savings are credited back to customers through reduced rates. Subject to the BCUC's approval, FortisBC Energy earned an incentive payment of approximately $1.5 million for the gas contract year ending October 31, 2020.

The current GSMIP program was approved by the BCUC following a comprehensive review in 2011. The BCUC has approved extensions of the program through October 31, 2022.

Price-Risk Management Plan

FortisBC Energy engages in price-risk management activities to mitigate the impact on customer rates of fluctuations in natural gas prices. These activities include: (i) physical gas purchasing and storage strategies; (ii) current quarterly commodity rate-setting and a deferral account mechanism; and (iii) the use of derivative instruments, which were implemented pursuant to a price-risk management plan approved by the BCUC, as discussed below.

In May 2020 FortisBC Energy filed its Winter 2020-2021 Sumas Risk Mitigation Application with the BCUC to implement Sumas hedging strategies for the 2020-2021 winter season to mitigate the impact of price spikes and sustained elevated prices at the Sumas market hub. The BCUC approved the application in July 2020 and the hedging strategies were implemented in July and August 2020.

Unbundling

A Customer Choice program at FortisBC Energy allows eligible commercial and residential customers to buy their natural gas commodity supply from FortisBC Energy or from third-party marketers. FortisBC Energy continues to provide the delivery service of the natural gas to all its customers. For the year ended December 31, 2020, approximately 5% of eligible commercial customers and 3% of eligible residential customers purchased their commodity supply from alternate providers.

FortisAlberta

FortisAlberta is a regulated electricity distribution utility operating in Alberta. Its business is the ownership and operation of electric distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct retail sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta around and between the cities of Edmonton and Calgary, totalling approximately 91,000 circuit km of distribution lines. FortisAlberta's distribution network serves approximately 572,000 customers and met a peak demand of 2,770 MW in 2020.

Market and Sales

FortisAlberta's annual energy deliveries were 16,092 GWh in 2020 compared to 16,887 GWh in 2019. Revenue was $596 million in 2020 compared to $598 million in 2019.

The following table compares the composition of FortisAlberta's 2020 and 2019 revenue and energy deliveries by customer class.

	Revenue *(%)*		**GWh Deliveries** *(%)* [1]	
	2020	2019	**2020**	2019
Residential	**43.5**	42.6	**29.3**	27.3
Commercial	**24.3**	24.7	**13.3**	13.8
Industrial	**20.0**	21.2	**57.4**	58.9
Other [2]	**12.2**	11.5	—	—
Total	**100.0**	100.0	**100.0**	100.0

[1] *GWh percentages exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 6,932 GWh in 2020 and 6,940 GWh in 2019, based on an interim settlement that is expected to be finalized in May 2021, and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

[2] *Includes rate riders, deferrals and adjustments.*

Franchise Agreements

FortisAlberta serves customers in various municipalities throughout its service area. From time to time, municipal governments in Alberta consider creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be determined on the basis of a methodology approved by the AUC. Additionally, under the*Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should compensate FortisAlberta for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

FortisAlberta holds franchise agreements with 163 municipalities within its service area. The franchise agreements include 10-year terms with an option to renew for up to two subsequent five-year terms. Over 99% of FortisAlberta's franchise agreements were entered into in 2012 and subsequent years, pursuant to which the initial terms will not expire until the end of 2022 and beyond, with notices to extend the current agreement to be provided one year in advance of expiry.

FortisBC Electric

FortisBC Electric is an integrated regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines and a large network of distribution assets located in the southern interior of British Columbia. FortisBC Electric serves approximately 182,000 customers and met a peak demand of 740 MW in 2020. FortisBC Electric's T&D assets include approximately 7,300 circuit km of T&D lines.

FortisBC Electric is also responsible for operation, maintenance and management services at the 493-MW Waneta hydroelectric generating facility owned by BC Hydro and the 335-MW Waneta Expansion, the 149-MW Brilliant hydroelectric plant, the 120-MW Brilliant hydroelectric expansion plant and the 185-MW Arrow Lakes generating station, all ultimately owned by CBT and CPC.

Market and Sales

Electricity sales were 3,291 GWh in 2020, compared to 3,326 GWh in 2019. Revenue was $424 million in 2020, compared to $418 million in 2019.

The following table compares the composition of FortisBC Electric's 2020 and 2019 revenue and electricity sales by customer class.

	Revenue *(%)*		**GWh Sales** *(%)*	
	2020	2019	**2020**	2019
Residential	**50.5**	48.9	**40.5**	38.8
Commercial	**27.1**	27.1	**29.4**	29.4
Industrial	**12.6**	13.2	**17.0**	17.6
Other [(1)]	**9.8**	10.8	**13.1**	14.2
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue and GWh sales from wholesale customers*

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and PPAs. FortisBC Electric owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW, which provide approximately 45% of its energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the multi-party CPA that enables the five separate owners of nine major hydroelectric generating plants, with a combined capacity of approximately 1,900 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	**Capacity** *(MW)*	**Owners**
Canal Plant	580	BC Hydro
Waneta Dam	493	BC Hydro
Waneta Expansion	335	Waneta Expansion Power Corporation
Kootenay River System	225	FortisBC Electric
Brilliant Dam	149	Brilliant Power Corporation
Brilliant Expansion	120	Brilliant Expansion Power Corporation
Total	**1,902**	

Brilliant Power Corporation, Brilliant Expansion Power Corporation, Teck Metals Ltd., Waneta Expansion Power Corporation and FortisBC Electric are collectively defined in the CPA as the entitlement parties. The CPA enables BC Hydro and the entitlement parties to generate more power from their respective generating plants than they could if they operated independently through coordinated use of water flows, subject to the 1961 *Columbia River Treaty* between Canada and the US, and coordinated operation of storage reservoirs and generating plants. Under the CPA, BC Hydro takes into its system all power actually generated by the plants listed in the table above. In exchange for permitting BC Hydro to determine the output of these facilities, each of the entitlement parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is based on 50-year historical water flows and the plants' generating capabilities. The entitlement parties receive their defined entitlements irrespective of actual water flows to the entitlement parties' generating plants. BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The entitlement parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and, therefore, do not face hydrology variability in generation supply planning. However, FortisBC Electric retains rights to its original water licences and flows in perpetuity. Should the CPA be terminated, the output of FortisBC Electric's Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Electric receives under the CPA. The CPA does not affect FortisBC Electric's ownership of its physical generation assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

FortisBC Electric's remaining electricity supply is acquired primarily through long-term PPAs with a number of counterparties, including the Brilliant PPA, the BC Hydro PPA and the Waneta Expansion Capacity Agreement. Additionally, FortisBC Electric purchases capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. These market purchases provided approximately 10% of FortisBC Electric's energy supply requirements in 2020. FortisBC Electric's PPAs and market purchases have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates.

Other Electric

Other Electric consists of utilities in eastern Canada and the Caribbean as follows: Newfoundland Power; Maritime Electric; FortisOntario; a 39% equity investment in Wataynikaneyap Partnership; an approximate 60% controlling interest in Caribbean Utilities; FortisTCI; and a 33% equity investment in Belize Electricity.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on PEI. FortisOntario primarily provides integrated electric utility service through its three regulated operating utilities with its customer base primarily in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

The Wataynikaneyap Partnership has a mandate of connecting 17 remote First Nations Communities in Northwestern Ontario to the electricity grid. The partnership is equally owned by 24 First Nations communities (51%), in partnership with FortisOntario (39%) and Algonquin Power & Utilities Corp. (10%). FortisOntario is responsible for construction, management and operation of the transmission line. Construction began on the project in 2019 and the first transmission tower was erected and substation ground grid installed in the third quarter of 2020. The project is on track for completion by the end of 2023.

Caribbean Utilities is an integrated regulated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. FortisTCI is an integrated regulated electric utility on the Turks and Caicos Islands. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize. Belize Electricity is excluded from the discussion of this segment as Fortis holds a 33% minority interest in this entity.

The following table sets out the customers, installed generating capacity, peak demand and kilometers of T&D lines for the segment.

		Peak Demand	**T&D Lines**	**Generating Capacity**	
	Customers	*(MW)*	*(circuit km)*	*(MW)*	**Resource Type(s)**
Newfoundland Power	270,000	1,356	12,500	143	Hydroelectric, Gas, Diesel
Maritime Electric	84,000	287	6,300	130	Thermal, Diesel
FortisOntario [(1)]	67,000	258	3,500	5	Natural Gas Cogeneration
Caribbean Utilities [(2)]	31,000	109	800	161	Diesel
FortisTCI	15,000	40	700	91	Diesel
Total	**467,000**	**2,050**	**23,800**	**530**	

(1) *FortisOntario also owns a 10% interest in certain regional electric distribution companies serving approximately 40,000 customers.*
(2) *Includes 24 km of high-voltage submarine cable*

Market and Sales

Electricity sales attributable to Other Electric were 9,175 GWh in 2020, compared to 9,366 GWh in 2019. Revenue was $1,485 million in 2020, compared to $1,467 million in 2019.

The following table compares the composition of revenue and electricity sales by customer class for Other Electric in 2020 and 2019.

	Revenue *(%)*		**GWh Sales** *(%)*	
	2020	2019	**2020**	2019
Residential	**58.7**	56.0	**57.3**	55.4
Commercial	**37.4**	40.1	**39.1**	41.2
Industrial	**1.9**	1.9	**2.7**	2.6
Other [(1)]	**2.0**	2.0	**0.9**	0.8
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Newfoundland Power

Approximately 93% of Newfoundland Power's energy requirements are purchased from NL Hydro with the remaining 7% generated by Newfoundland Power generating facilities. The principal terms of the supply arrangements with NL Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

NL Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect NL Hydro's marginal cost of generating electricity.

The completion of Nalcor Energy's $13.1 billion Muskrat Falls hydroelectric generation development and associated transmission assets is further delayed and is now expected in September 2021. Energy from the Muskrat Falls project is expected to supply a significant portion of NL Hydro's electricity requirements, and in turn, Newfoundland Power's electricity requirements. Uncertainty remains regarding supply adequacy and reliability of the province of Newfoundland and Labrador's electrical system after commissioning. The amount and timing of any future wholesale electricity rate changes, including those associated with the Muskrat Falls project, are uncertain; however, future increases in supply costs from NL Hydro are expected to increase electricity rates that Newfoundland Power charges to its customers.

Maritime Electric

Maritime Electric is interconnected to the Province of New Brunswick via four provincially owned submarine cables with a total capacity of 560 MW. The company purchases its power supply requirements through various Energy Purchase Agreements from NB Power, a New Brunswick Crown corporation and renewable energy produced on PEI by facilities owned by the PEI Energy Corporation. Company-owned on-Island generation stations totalling 130 MW are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has the following contracts with NB Power: (i) an energy supply agreement covering the period March 1, 2019 to December 31, 2026; (ii) a transmission capacity contract allowing Maritime Electric to reserve 30 MW of capacity to PEI expiring November 2032; and (iii) an entitlement agreement for approximately 4.55% of the output from NB Power's Point Lepreau Nuclear Generating Station for the life of the unit. The company also has several renewable energy contracts with the PEI Energy Corporation for the purchase of energy for remaining periods ranging from two to 16 years.

As part of Maritime Electric's entitlement agreement for the Point Lepreau Nuclear Generating Station, it is required to pay its share of the capital and operating costs of the unit.

FortisOntario

The power requirements of FortisOntario's service territories are met through various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO, purchases approximately 75% of energy requirements in the Gananoque region from Hydro One Networks Inc., and the remaining 25% from five hydroelectric generating plants owned by EO Generation LP. Algoma Power purchases its energy requirements primarily from IESO.

Under the Standard Supply Code of the Ontario Energy Board, Canadian Niagara Power and Algoma Power are obligated to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under a new contract that commenced in January 2020 and expires in December 2030. The new contract provides a minimum of 537 GWh of energy per year and up to 145 MW of capacity at any one time.

Caribbean Utilities

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for its customers. Caribbean Utilities is party to primary and secondary fuel supply contracts with two different suppliers from whom it is committed to purchasing 60% and 40%, respectively, of its diesel fuel requirements for its diesel-powered generating plant. Caribbean Utilities executed two 24-month fuel supply contracts in June 2018 with the option to renew for two additional terms of 18 months at the end of each term. In June 2020 Caribbean Utilities exercised its option to renew for 18 months.

FortisTCI

FortisTCI relies upon in-house diesel-powered generation to produce electricity for its customers. FortisTCI has installed 1 MW of rooftop solar in partnership with nine commercial customers through its Utility Owned Renewable Energy Program. The company continues to engage with the Government of the Turks and Caicos Islands on the progress of the draft Electricity (Amendment) Bill, designed to enable the development of renewable energy within the country.

FortisTCI has contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 64 million litres per annum.

Non-Regulated

Energy Infrastructure

The Corporation's Energy Infrastructure segment consists of a natural gas storage facility in British Columbia (Aitken Creek) and three hydroelectric generation facilities in Belize with a combined capacity of 51 MW held through the Corporation's subsidiary BECOL. In April 2019 Fortis sold its 51% ownership interest in long-term contracted generation assets in British Columbia, the Waneta Expansion.

Aitken Creek is the only underground natural gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet. Fortis holds a 93.8% ownership interest in Aitken Creek through its subsidiary ACGS, acquired in 2016. ACGS contracts with third parties for both lease and park transactions and also holds its own proprietary capacity.

Generation assets in Belize consist of three hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060.

Market and Sales

Energy sales were 229 GWh in 2020, compared to 144 GWh in 2019. Revenue was $88 million in 2020, compared to $82 million in 2019.

Corporate and Other

The Corporate and Other segment captures expense and revenue items 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.

HUMAN RESOURCES

Fortis and its subsidiaries have 8,961 employees, with 53% in Canada, 42% in the US and 5% in other countries. The following table provides the breakdown of employees by reportable segment.

	Employees	Participation in a Collective Agreement	Union(s)	Collective Agreement(s) Expiry Date(s)
Regulated Utilities				
ITC	699	None	—	—
UNS Energy	2,057	50 %	IBEW	June 2021 – February 2025
Central Hudson	1,061	57 %	IBEW	March 2021 – April 2022
FortisBC Energy [(1)]	1,954	61 %	IBEW, MoveUP	March 2019 [(2)] – June 2023
FortisAlberta	1,085	79 %	UUWA	December 2020 [(3)]
FortisBC Electric	560	70 %	IBEW, MoveUP	January 2021 [(4)] – June 2023
Other Electric [(5)]	1,422	39 %	CUPE, IBEW, PWU	January 2022 – December 2023
Non-Regulated				
Energy Infrastructure [(6)]	68	None	—	—
Corporate and Other [(7)]	55	None	—	—
Total	**8,961**	**52 %**		

(1) *Includes employees at FHI*
(2) *The collective agreement between FortisBC Energy and IBEW covering 565 FortisBC Energy employees expired on March 31, 2019 and is currently under renegotiation. Mediation was initiated in May 2020 and is ongoing. Operations have not been impacted to date.*
(3) *The collective agreement between FortisAlberta and the UUWA expired on December 31, 2020 and is currently under renegotiation.*
(4) *The collective agreement between FortisBC Electric and IBEW covering 192 FortisBC Electric employees expired on January 31, 2021 and is currently under renegotiation.*
(5) *Includes employees at Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and FortisTCI. Excludes Belize Electricity.*
(6) *Includes employees at Aitken Creek (staffed by FortisBC Midstream Inc.), BECOL and FortisBC Alternative Energy Services Inc.*
(7) *Employees at Fortis Inc.*

The Corporation's culture is built on safety, diversity and integrity. Fortis employees are driven to make good decisions, work hard and work safely. Fortis and its utilities respect their employees' freedom to associate and strive to maintain positive and constructive relationships with labour associations and unions.

The Corporation's subsidiaries are required to develop and retain skilled workforces for their operations. Many of the employees of the Corporation's utilities possess specialized skills and training and Fortis must compete in the marketplace for these workers. The Corporation's significant capital plan may present challenges to ensure its utilities have the qualified workforce necessary to complete the capital work initiatives.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that involve a claim for damages exceeding 10% of the Corporation's current assets in respect of which the Corporation is or was a party, or in respect of which any of the Corporation's property is or was the subject during the year ended December 31, 2020, nor are there any such proceedings known to the Corporation to be contemplated.

Information related to the Corporation's legal proceedings can be found in Note 28 of the Financial Statements, which are incorporated by reference in this AIF and available on SEDAR and EDGAR.

The Corporation's utilities operate under a cost of service regulation, in combination with performance-based rate-setting mechanisms in certain jurisdictions, and are regulated by the regulatory body in their respective operating jurisdiction. During the year ended December 31, 2020, there have not been any: (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements entered into by the Corporation before a court relating to securities legislation or with a securities regulatory authority.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's utilities, refer to the "Regulatory Highlights" section of the MD&A and to Notes 2 and 8 of the Financial Statements, each of which are incorporated by reference in this AIF and available on SEDAR and EDGAR.

RISK FACTORS

For information with respect to the Corporation's business risks, refer to the "Business Risks" section of the MD&A, which is incorporated by reference in this AIF and available on SEDAR and EDGAR.

SUSTAINABILITY

Fortis is committed to being a strong energy partner for its communities by operating in an environmentally and socially responsible manner. The Corporation is focused on maintaining infrastructure to deliver energy more efficiently and to facilitate the delivery of cleaner energy. Fortis believes that responsible environmental and sustainability management not only creates business value, but it is also good for the planet and our customers.

To bring focus and accountability to sustainability, oversight has been integrated into each senior level of responsibility at Fortis. The Board is responsible for risk management oversight and ensuring that business is conducted to meet high standards of environmental and social responsibility. The Governance and Sustainability Committee of the Board is responsible for overseeing governance structure and sustainability practices, including reviewing programs designed to promote corporate citizenship and environmental and social responsibility. The Executive Vice President, Sustainability and Chief Human Resource Officer is responsible for enterprise-wide sustainability and stewardship. Local management teams and boards of directors at each of the Corporation's utilities are responsible for operational aspects of sustainability. Sustainability performance impacts how all Fortis executives are compensated.

Fortis is primarily an energy delivery company with 93% of its assets dedicated to this function. This focus on energy delivery presents a unique opportunity to facilitate the delivery of cleaner energy to customers and naturally limits our impact on the environment when compared with energy generation intensive businesses. Although Fortis has limited fossil-fuel generation exposure, the Corporation is committed to reducing carbon emissions and delivering more sustainable energy to our customers.

The Corporation's direct GHG emissions come primarily from its generation assets, including fossil fuel-based generation representing 5% of the Corporation's total assets. In September 2020 the Corporation announced it is building on its low emissions profile by establishing a corporate-wide target to reduce carbon emissions by 75% by 2035 from a 2019 base year. Fortis expects to achieve the target through delivering on TEP's goals to reduce carbon emissions, described below. TEP is the Corporation's primary owner of fossil fuel-based generation. Clean energy initiatives across the Corporation's other utilities will also contribute to achieving this goal.

TEP has set a target to reduce carbon emissions by 80% by 2035. Key elements of the plan include adding approximately 2,400 MW of new wind and solar power systems and 1,400 MW of energy storage systems. TEP also plans to exit coal generation by ramping down and ultimately retiring TEP's two units at the coal-fired Springerville Generating Station in 2027 and 2032. This timeline will allow TEP to reduce the plant's workforce through attrition while providing time for the company to help the local community minimize the impact of the units' retirement.

FortisBC Energy and FortisBC Electric have set a combined goal to reduce GHG emissions associated with customers' energy use by 30% by the year 2030. To achieve this objective, the utilities will focus on tripling investment in energy efficiency projects, increasing renewable natural gas supply and focusing on low and zero-carbon vehicles and transportation infrastructure. This overall GHG emission reduction target is supported by FortisBC Energy's aim to have 15% of its gas supply come from renewable sources by 2030.

The Corporation's environmental statement sets out its commitment to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems and seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources. The Fortis Sustainability Working Group, comprising key leaders from across the Fortis group of utilities, enables communication and sharing of information among the Corporation's utilities on sustainability performance, issues and opportunities. Each operating subsidiary has extensive environmental compliance programs aligned with the ISO 14001 standard, regularly reviews its environmental management systems and protocols, strives for continual performance improvement and sets and reviews its own environmental objectives, targets and programs. The Fortis Operating Group, a group of senior operational executives from all utilities, meets regularly to share best practices and identify opportunities for collaboration on a range of topics including environment, health and safety.

Social and Environmental Policies

The Corporation and its utilities each have a range of social and environmental policies, programs and practices. Fortis has a Code of Conduct which is guided by the Corporation's purpose and values and sets out standards for the ethical conduct of its business, applicable to all of its directors, officers and employees, and to the extent feasible also to its consultants, contractors and representatives. The core principles of the Fortis Code of Conduct apply universally across the organization, with each operating subsidiary adopting its own substantially similar Code. Fortis and its utilities hold regular Code of Conduct employee training; and all Fortis employees annually certify compliance.

The Code of Conduct is supported by other policies that outline the behaviour expected from management and employees, including the Anti-Corruption Policy and Respectful Workplace Policy. All Fortis operating subsidiaries have policies in place that uphold the Corporation's values as contained in these policies and demonstrate their commitment to ensuring equal opportunity and providing safe, respectful work environments.

Each Fortis operating subsidiary has a Whistleblower Policy to support the reporting of conduct that may breach the subsidiary's Code of Conduct or other workplace policies.

The Corporation's operating subsidiaries are also responsible for implementing policy frameworks that reflect their unique operations and jurisdictions, while addressing certain common priority areas, including: occupational health and safety; environmental stewardship; non-discrimination and equal opportunity in hiring and promotion; and support of local communities.

The Corporation's Board and Executive Diversity Policy describes the principles and objectives for diversity among the Board and executive leadership, including a commitment to maintaining a Board where at least one-third of its independent directors are represented by each gender. Currently, 40% of the Corporation's directors and 42% of its executive leadership team are female. 60% of Fortis utilities have either a female president or female board chair.

Advancing inclusion and diversity is a priority at Fortis. In 2019 the Corporation adopted a formal Inclusion and Diversity Commitment that applies to all employees at Fortis and its operating subsidiaries. The commitment is supported by a framework built upon three pillars - talent, culture and community. Within the framework each utility develops an action plan specific to its inclusion and diversity priorities in addition to an overarching three-year action plan that articulates enterprise initiatives focused on creating equal pathways to leadership, strengthening inclusion and diversity accountability and modelling thought leadership. An Inclusion and Diversity Council with diverse, senior level representation from across the Fortis organization guides the inclusion and diversity strategy and its implementation.

Sustainability Regulation and Environmental Contingencies

As part of the regulatory process, operating subsidiaries engage with stakeholders, including community groups, regulators and customers, to consult on the potential environmental impact of their operations. Fortis and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment. Environmental compliance involves significant operating and capital costs. At the Corporation's regulated utilities, prudently incurred costs associated with environmental protection and compliance are generally eligible for recovery in customer rates.

The following environmental contingencies have been made as of December 31, 2020:

Mine Reclamation at Generation Facilities Not Operated by TEP. TEP pays ongoing reclamation costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP is permitted to fully recover these costs from customers and, accordingly, these costs are deferred as a regulatory asset.

TEP is liable for a portion of final mine reclamation costs upon closure of the mines servicing San Juan and Four Corners. TEP's estimated share of final mine reclamation costs at both mines is $61 million (US$48 million) upon expiration of the related coal supply agreements, which expire in 2022 and 2031, respectively. An aggregate liability balance related to San Juan and Four Corners final mine reclamation of $51 million (US$40 million) and $47 million (US$36 million) as at December 31, 2020 and 2019, respectively, was recognized on the balance sheet.

Former Manufactured Gas Plant Facilities. Environmental regulations require Central Hudson to investigate sites at which Central Hudson or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate these sites. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2020, an obligation of $95 million (US$75 million) was recognized. Central Hudson has notified its insurers and intends to seek reimbursement where insurance coverage exists. Further, as authorized by the NYPSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for manufactured gas plant site investigation and remediation and the associated rate allowances.

CAPITAL STRUCTURE AND DIVIDENDS

Description of Capital Structure

The authorized share capital of the Corporation consists of an unlimited number of common shares without nominal or par value, an unlimited number of first preference shares without nominal or par value, and an unlimited number of second preference shares without nominal or par value.

As at February 11, 2021, the Corporation had issued and outstanding 466.8 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.7 million First Preference Shares, Series H; 2.3 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M.

For a summary of the terms and conditions of the Corporation's authorized securities, and trading information for the Corporation's publicly listed securities, refer to Exhibit "A" and Exhibit "B" of this AIF.

Dividends and Distributions

The declaration and payment of dividends on the Corporation's common shares and first preference shares are at the discretion of the Board. Dividends on the common shares are typically paid quarterly, on the first day of March, June, September and December of each year. Dividends on the Corporation's First Preference Shares, Series F, G, H, I, J, K and M are typically also paid quarterly.

In September 2020 Fortis increased its quarterly dividend per common share 5.8% to $0.505 per share, or $2.02 on an annualized basis. In November 2020 the Board declared a first quarter 2021 dividend on the common shares of $0.505 per share and on the First Preference Shares, Series F, G, H, I, J, K and M in accordance with the applicable prescribed rate. The first quarter dividends on the common shares and the First Preference Shares, Series F, G, H, I, J, K and M are to be paid on March 1, 2020 to holders of record as of February 16, 2021.

The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	2020	2019	2018
Common Shares	1.9650	1.8550	1.7500
First Preference Shares, Series F[(1)]	1.2250	1.2250	1.2250
First Preference Shares, Series G[(2)]	1.0983	1.0983	1.0345
First Preference Shares, Series H[(3)]	0.5003	0.6250	0.6250
First Preference Shares, Series I[(4)]	0.4987	0.7771	0.7116
First Preference Shares, Series J[(1)]	1.1875	1.1875	1.1875
First Preference Shares, Series K[(5)]	0.9823	0.9823	1.0000
First Preference Shares, Series M[(6)]	0.9783	1.0133	1.0250

(1) *The dividend rate on the First Preference Shares, Series F and First Preference Shares, Series J are fixed and do not reset.*
(2) *The annual dividend per share was reset to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.*
(3) *The annual dividend per share was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*
(4) *The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.*
(5) *The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and were entitled to receive cumulative dividends in the amount of $1.0000 per share per annum to but excluding March 1, 2019. The annual fixed dividend per share for the First Preference Shares, Series K was reset to $0.9823 for the five-year period from March 1, 2019 to but excluding March 1, 2024.*
(6) *The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 at $25.00 per share and were entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years. The annual fixed dividend per share for the First Preference Shares, Series M was reset to $0.9783 for the five-year period from December 1, 2019 to but excluding December 1, 2024.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preference shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has $500 million and $1.3 billion of unsecured committed revolving corporate credit facilities, maturing in April 2021 and July 2024, respectively, that are available for general corporate purposes. The credit facilities contain a covenant that provides that Fortis 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%.

As at December 31, 2020 and 2019, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

Credit Ratings

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely DBRS Morningstar, S&P, Moody's and/or Fitch. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's debt credit ratings as at February 11, 2021.

Company/Security	DBRS Morningstar	S&P	Moody's
Fortis - Unsecured Debt [(1)(2)]	BBB (high), Positive	BBB+, Negative	Baa3, Stable
Caribbean Utilities - Unsecured Debt [(3)]	A (low), Stable	BBB+, Negative	—
Central Hudson - Unsecured Debt [(4) (5)]	—	A-, Stable	A3, Negative
FortisAlberta - Unsecured Debt	A (low), Stable	A-, Negative	Baa1, Stable
FortisBC Electric			
Secured Debt	A (low), Stable	—	—
Unsecured Debt	A (low), Stable	—	Baa1, Stable
Commercial Paper	R-1 (low), Stable	—	—
FortisBC Energy			
Unsecured Debt	A, Stable	—	A3, Stable
Commercial Paper	R-1 (low), Stable	—	—
ITC Holdings			
Unsecured Debt [(2)]	—	BBB+, Negative	Baa2, Stable
Commercial Paper [(2)]	—	A-2, Negative	Prime-2, Stable
ITC Great Plains - First Mortgage Bonds [(2)]	—	A, Negative	A1, Stable
ITC Midwest - First Mortgage Bonds [(2)]	—	A, Negative	A1, Stable
ITCTransmission - First Mortgage Bonds [(2)]	—	A, Negative	A1, Stable
Maritime Electric - Secured Debt	—	A, Stable	—
METC - Secured Debt [(2)]	—	A, Negative	A1, Stable
Newfoundland Power - First Mortgage Bonds	A, Stable	—	A2, Stable
TEP			
Unsecured Debt [(2)]	—	A-, Negative	A3, Stable
Unsecured Bank Credit Facility			A3, Stable
UNS Electric			
Unsecured Debt	—	—	A3, Stable
Unsecured Bank Credit Facility	—	—	A3, Stable
UNS Gas - Unsecured Debt	—	—	A3, Stable
UNS Energy - Unsecured Bank Credit Facility	—	—	Baa1, Stable

(1) *Between March and August 2020, all three rating agencies affirmed the Corporation's credit ratings and outlooks. In May 2020 DBRS revised its outlook to positive from stable due to: (i) significant reduction of nonconsolidated corporate debt following the sale of a 51% interest in the Waneta Expansion and the $1.2 billion common equity issuance in December 2019; (ii) solid consolidated credit metrics in 2019 and expected to continue in the near-to-medium term; and (iii) a continued strong business risk profile at regulated utilities.*

(2) *In March 2020 S&P reaffirmed its outlook to remain negative due to the potential impacts over the next 6 to 12 months to the consolidated financial measures should the COVID-19 pandemic or macroeconomic downturn persist.*

(3) *In March 2020 S&P revised its outlook to negative from stable due to the COVID-19 pandemic and its potential impacts on Cayman's tourism industry.*

(4) *In October 2020 Moody's revised its outlook to negative from stable citing the company's capital program and the possible impact on financial metrics considering the current regulatory environment in New York State.*

(5) *Central Hudson's senior unsecured debt is also rated by Fitch at 'A-, stable'.*

DBRS Morningstar rates long-term debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS Morningstar's rating scale provides an opinion on the risk of default, which is the risk that an issuer with fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. The ratings are also based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories of '(high)' or '(low)'. The absence of either a '(high)' or '(low)' designation indicates the rating is in the middle of a category.

According to DBRS Morningstar, a rating of A is assigned to a long-term debt instrument that has good credit quality, with the issuer having substantial capacity to pay its financial obligations, but credit quality is less than AA-rated instruments and may be vulnerable to future events, but qualifying negative factors are considered reasonable. A rating of BBB is assigned to a long-term debt instrument that has adequate credit quality, with the issuer considered having acceptable capacity to pay its financial obligations but may be vulnerable to future events.

DBRS Morningstar rates short-term debt on a rating scale that ranges from R-1 to D, which represents the range from highest to lowest quality of such securities. DBRS Morningstar also uses '(high)', '(middle)', or '(low)' designations to indicate the relative standing of securities within a particular rating category. Such modifiers are not added to ratings below R-2. According to DBRS Morningstar, a rating of R-1 (low) means that the short-term debt obligation has good credit quality, the issuer has substantial ability to repay short-term debt obligations and may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. Such modifiers are not added to ratings below CCC. S&P's long-term debt rating scale provides an opinion about the creditworthiness of an issuer with respect to the specific financial obligation and the issuer's capacity and willingness to meet its financial commitments on the obligation in accordance with its terms. According to S&P, a rating of A is assigned to long-term debt instruments that are somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories. However, the issuer's capacity to meet its financial obligations is still strong. Debt instruments rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the issuer to meet its financial commitments on the obligation.

S&P rates short-term obligations on a rating scale that ranges from A-1 to D, which represents the range from the highest to lowest quality of such securities. Within only the A-1 category may certain obligations be designated with a '+', indicating that the issuer's capacity to meet its financial commitments under these obligations is extremely strong. According to S&P, a short-term obligation rated A-2 is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the issuer's capacity to meet its financial commitments on the short-term obligation is satisfactory.

Moody's rates long-term debt on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 to each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking in its generic rating category and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's states that its long-term debt ratings are opinions of relative risk of fixed-income obligations and reflect both the likelihood of default or impairment and any expected financial loss suffered in the event of default or impairment. According to Moody's, a rating of Baa is assigned to long-term debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

Moody's rates short-term debt on a rating scale that includes four designations. From highest to lowest relative repayment ability of rated issuers, such designations are Prime-1, Prime-2, Prime-3 and Not Prime. Short-term obligations with a Not Prime rating do not fall within any of the Prime rating categories. According to Moody's, a rating of Prime-2 means that an issuer has a strong ability to repay short-term debt obligations.

Fitch rates long-term debt on a rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. Fitch uses '+' or '-' designations to indicate the relative status of securities within a particular rating category. Such modifiers are not added to the AAA rating or to ratings below CCC. Fitch states that its credit ratings provide an opinion on the relative ability of an entity to meet its financial commitments under long-term obligations and address relative vulnerability to default. Fitch's credit ratings do not directly address any risk other than credit risk. According to Fitch, a long-term

obligation rated A denotes the expectation of low credit risk, with strong capacity for payment of financial commitments. The capacity may, nevertheless, be more vulnerable to adverse business or economic conditions than is the case for higher ratings.

The Corporation and/or each of its currently rated utilities pay DBRS Morningstar, S&P, Moody's and/or Fitch an annual monitoring fee and a one-time fee in connection with each rated issuance.

DIRECTORS AND OFFICERS

The Board has governance guidelines that cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and are eligible for re-election until the annual meeting of shareholders following the date they turn 72 or until they have served on the Board for 12 years, whichever is earlier. Exceptions may be made by the Board if it is in the best interests of the Corporation and the Director has received solid annual performance evaluations, has the necessary skills and experience and meets the other Board policies and legal requirements for Board service.

The following table sets out the name, province or state, and country of residence of each of the Directors of the Corporation and their principal occupations during the five preceding years. Each Director's current term expires at the next annual meeting of shareholders.

Name, Residence, Principal Occupation Within Five Preceding Years	Director Since	Committees [1]		
		AC	GS	HR
DOUGLAS J. HAUGHEY *(Chair),* Alberta, Canada Corporate Director.	2009	I	I	I
TRACEY C. BALL, British Columbia, Canada Corporate Director.	2014	**C**	I	
PIERRE J. BLOUIN, Quebec, Canada Corporate Director.	2015		**C**	I
PAUL J. BONAVIA, Texas, USA Corporate Director.	2018		I	I
LAWRENCE T. BORGARD, Florida, USA Corporate Director. President and Chief Operating Officer of Integrys Energy Group from 2014 to 2015.	2017	I		I
MAURA J. CLARK, New York, USA Corporate Director.	2015	I	I	
MARGARITA K. DILLEY, District of Columbia, USA Corporate Director.	2016	I		I
JULIE A. DOBSON, Maryland, USA Corporate Director.	2018		I	I
DAVID G. HUTCHENS, Arizona, USA President and Chief Executive Officer of the Corporation.	2021	[2]		
JO MARK ZUREL, Newfoundland and Labrador, Canada Corporate Director. President of Stonebridge Capital Inc., a private investment company from 2006 to March 2019.	2016	I		**C**

[1] *Audit Committee, Governance and Sustainability Committee and Human Resources Committee. "C" represents Chair.*
[2] *Mr. Hutchens does not serve on any of the committees because he is the President and Chief Executive Officer of the Corporation.*

The following table sets out the name, province or state, and country of residence of each of the executive officers of Fortis and indicates the office held and principal occupations of the executive officers during the five preceding years.

Name, Residence, Principal Occupation During the Five Preceding Years	Office
DAVID G. HUTCHENS, Arizona, USA President and Chief Executive Officer since January 2021. Chief Operating Officer from January 2020 to December 2020 and Executive Vice President, Western Utility Operations from January 2018 to January 2020. Chief Executive Officer of UNS Energy from January 2020 to December 2020 and President and Chief Executive Officer of UNS Energy from May 2014 to January 2020.	President and Chief Executive Officer
JOCELYN H. PERRY, Newfoundland and Labrador, Canada Executive Vice President, Chief Financial Officer since June 2018. President and Chief Executive Officer of Newfoundland Power from 2017 to May 2018, Chief Financial Officer and Chief Operating Officer from 2016 to 2017 and Vice President, Finance & Chief Financial Officer from 2007 to 2016.	Executive Vice President, Chief Financial Officer
NORA M. DUKE, Newfoundland and Labrador, Canada Executive Vice President, Sustainability and Chief Human Resource Officer since December 2017 and Executive Vice President, Corporate Services and Chief Human Resource Officer from August 2015 to December 2017.	Executive Vice President, Sustainability and Chief Human Resource Officer
JAMES P. LAURITO, Florida, USA Executive Vice President, Business Development and Chief Technology Officer since May 2019 and Executive Vice President, Business Development since April 2016. President and Chief Executive Officer of Central Hudson from 2010 to April 2016.	Executive Vice President, Business Development and Chief Technology Officer
JAMES R. REID, Ontario, Canada Executive Vice President, Chief Legal Officer and Corporate Secretary since March 2018. Partner with Davies Ward Phillips & Vineberg LLP from 2003 to March 2018.	Executive Vice President, Chief Legal Officer and Corporate Secretary
GARY J. SMITH, Newfoundland and Labrador, Canada Executive Vice President, Eastern Canadian and Caribbean Operations since June 2017. President and Chief Executive Officer of Newfoundland Power from 2014 to June 2017.	Executive Vice President, Eastern Canadian and Caribbean Operations
STEPHANIE A. AMAIMO, Michigan, USA Vice President, Investor Relations since October 2017, Director, Investor Relations from 2016 to October 2017 and Director, Investor Relations of ITC Holdings from 2015 to 2016.	Vice President, Investor Relations
KAREN J. GOSSE, Newfoundland and Labrador, Canada Vice President, Treasury and Planning since April 2018. Vice President, Planning and Forecasting from November 2015 to April 2018.	Vice President, Treasury and Planning
RONALD J. HINSLEY, Michigan, USA Vice President, Chief Information Officer since May 2019.Vice President, Information Technology and Chief Information Officer of ITC Holdings since 2013.	Vice President, Chief Information Officer
KAREN M. MCCARTHY, Newfoundland and Labrador, Canada Vice President, Communications and Corporate Affairs since May 2018 and Director, Communications and Corporate Affairs from 2016 to May 2018. Director, Customer and Corporate Relations of Newfoundland Power from 2014 to 2016.	Vice President, Communications and Corporate Affairs
REGAN P. O'DEA, Newfoundland and Labrador, Canada Vice President, General Counsel since May 2017 and Associate General Counsel from 2014 to May 2017.	Vice President, General Counsel
JAMIE D. ROBERTS, Newfoundland and Labrador, Canada Vice President, Controller since March 2013.	Vice President, Controller

The directors and executive officers of Fortis, as a group, beneficially own, directly or indirectly, or exercise control or direction over 772,927 common shares, representing 0.17% of the issued and outstanding common shares of Fortis. The common shares are the only voting securities of the Corporation.

AUDIT COMMITTEE

Members

The members of the Corporation's Audit Committee are Tracey C. Ball (Chair), Lawrence T. Borgard, Maura J. Clark, Margarita K. Dilley, Douglas J. Haughey and Jo Mark Zurel. All members of the Audit Committee are independent and financially literate as those terms are defined by Canadian and US securities laws and TSX and NYSE requirements. In addition, the Board has determined that Tracey C. Ball, Maura J. Clark, Margarita K. Dilley and Jo Mark Zurel are financial experts and has designated each of them as "audit committee financial experts" under US securities laws.

The Corporation's Audit Committee Mandate, effective as of January 1, 2021, is attached as Exhibit "C" to this AIF.

Education and Experience

The education and experience of each Audit Committee member that is relevant to such member's responsibilities as a member of the Audit Committee are set out below.

Committee Member	Relevant Education and Experience
TRACEY C. BALL ***(Chair)***	Ms. Ball retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Chartered Professional Accountants of Alberta and the Chartered Professional Accountants of British Columbia. Ms. Ball was elected as a Fellow of the Chartered Professional Accountants of Alberta in 2007. She holds an ICD.D designation from the Institute of Corporate Directors.
LAWRENCE T. BORGARD	Mr. Borgard retired from Integrys Energy Group in 2015 where he was President and Chief Operating Officer and the Chief Executive Officer of each of Integrys' six regulated electric and natural gas utilities. Mr. Borgard graduated from Michigan State University with a Bachelor of Science (Electrical Engineering) and the University of Wisconsin-Oshkosh with an MBA. He also attended the Advanced Management Program at Harvard University Business School.
MAURA J. CLARK	Ms. Clark retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business, a leading energy retailer in Canada and the US. Previously Ms. Clark was Executive Vice President of North American Strategy and Mergers and Acquisitions for Direct Energy. Ms. Clark's prior experience includes investment banking and serving as Chief Financial Officer of an independent oil refining and marketing company. Ms. Clark graduated from Queen's University with a Bachelor of Arts in Economics. She is a member of the Association of Chartered Professional Accountants of Ontario.
MARGARITA K. DILLEY	Ms. Dilley retired from ASTROLINK International LLC in 2004, an international wireless broadband telecommunications company, where she was Vice President and Chief Financial Officer. Ms. Dilley's prior experience includes serving as Director, Strategy & Corporate Development as well as Treasurer for Intelsat. Ms. Dilley graduated from Cornell University with a Bachelor of Arts, from Columbia University with a Master of Arts and from Wharton Graduate School, University of Pennsylvania with an MBA.
DOUGLAS J. HAUGHEY	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Business Administration and from the University of Calgary with an MBA. Mr. Haughey holds an ICD.D designation from the Institute of Corporate Directors.
JO MARK ZUREL	Mr. Zurel was the president of Stonebridge Capital Inc., a private investment company, from 2006 to March 2019. From 1998 to 2006, Mr. Zurel was Senior Vice-President and Chief Financial Officer of CHC Helicopter Corporation. Mr. Zurel graduated from Dalhousie University with a Bachelor of Commerce and is a Fellow of the Association of Chartered Professional Accountants of Newfoundland and Labrador. He holds an ICD.D designation from the Institute of Corporate Directors.

Pre-Approval Policies and Procedures

The Audit Committee has established a policy that requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's external auditor. The Pre-Approval Policy for Independent Auditor Services describes the services that may be contracted from the external auditor and the related limitations and authorization procedures. This policy defines prohibited services, including but not limited to bookkeeping, valuations, internal audit and management functions, which may not be contracted from the external auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all services provided by the external auditor.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditors during each of the last two fiscal years are set out in the following table.

		Deloitte LLP	
($ thousands)	**Description of Fee Category**	**2020**	2019
Audit Fees	Core audit services	**9,362**	9,745
Audit-Related Fees	Assurance and related services that are reasonably related to the audit or review of the Financial Statements and are not included under Audit Fees	**1,267**	1,490
Tax Fees	Services related to tax compliance, planning and advice	**240**	669
Other	Services which are not Audit Services, Audit-Related Fees or Tax Fees	**22**	—
Total		**10,891**	11,904

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar in Canada for the common shares and first preference shares of Fortis is Computershare Trust Company of Canada in Montréal and Toronto.

The co-transfer agent and co-registrar in the US for the common shares is Computershare Trust Company, N.A. in Canton, MA, Jersey City, NJ and Louisville, KY.

Computershare Trust Company of Canada
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Computershare Trust Company, N.A.
Att: Stock Transfer Department
Overnight Mail Delivery: 462 South 4th Street, Louisville, KY 40202
Regular Mail Delivery: P.O. Box 505005, Louisville, KY 40233-5005
T: 303.262.0600 or 1.800.962.4284

INTERESTS OF EXPERTS

Deloitte LLP is independent with respect to the Corporation within the meaning of the US Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board (United States) and within the meaning of the rules of professional conduct of the Chartered Professional Accountants of Newfoundland and Labrador.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on the Corporation's website at www.fortisinc.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document unless otherwise stated.

Additional financial information is provided in the Corporation's MD&A and Financial Statements, which are incorporated by reference in this AIF and can be found on the Corporation's website at www.fortisinc.com, on SEDAR and on EDGAR.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 20, 2020 for the May 7, 2020 annual meeting of shareholders.

Requests for additional copies of the above-mentioned documents, as well as this 2020 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800).

EXHIBIT A: Summary of Terms and Conditions of Authorized Securities

Common Shares

Dividends on common shares are declared at the discretion of the Board. Holders of common shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the first preference shares and second preference shares and any other classes of shares of the Corporation entitled to receive dividends in priority to or ratably with the holders of the common shares, the Board may declare dividends on the common shares to the exclusion of any other classes of shares of the Corporation.

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 preference shares and second preference shares and any other classes 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.

Holders of the common shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other classes or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

Preference Shares

First Preference Shares

The following is a summary of the material rights, privileges, conditions and restrictions attached to the first preference shares as a class. The specific terms of the first preference shares, including the currency in which first preference shares may be purchased and redeemed and the currency in which any dividend is payable, if other than Canadian dollars, and the extent to which the general terms described herein apply to those first preference shares, is or will be as set forth in the applicable articles of amendment of Fortis relating to such series.

Issuance in Series

The Board may from time to time issue first preference shares in one or more series. Prior to issuing shares in a series, the Board is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of first preference shares.

Priority

The shares of each series of first preference shares rank on a parity with the first preference shares of every other series and in priority to all other shares of Fortis, including the second preference shares, as to the payment of dividends, return of capital and the distribution of assets in the event of the liquidation, dissolution or winding-up of Fortis, whether voluntary or involuntary, or any other distribution of the assets of Fortis among its shareholders for the purpose of winding-up its affairs.

Each series of first preference shares participates ratably with every other series of first preference shares in respect of accumulated cumulative dividends and returns of capital, if any, cumulative dividends, whether or not declared and any amount payable on the return of capital in respect of a series of first preference shares, if not paid in full.

Voting

The holders of the first preference shares are not entitled to any voting rights as a class except to the extent that voting rights may from time to time be attached to any series of first preference shares, and except as provided by law or as described below under the heading "Modification". At any meeting of the holders of first preference shares, each holder shall have one vote in respect of each first preference share held.

Redemption

Subject to the provisions of the *Corporations Act* (Newfoundland and Labrador) and any provisions relating to any particular series, Fortis, upon giving proper notice, may redeem out of capital or otherwise at any time, or from time to time, the whole or any part of the then outstanding first preference shares of any one or more series on payment for each such first preference share at such price or prices as may be applicable to such series. Subject to the foregoing, if only a part of the then outstanding first preference shares of any particular series is at any time redeemed, the shares to be redeemed will be selected by lot in such manner as the directors or the transfer agent for the first preference shares, if any, decide, or if the directors so determine, may be redeemed pro rata, disregarding fractions.

Modification

The class provisions attached to the first preference shares may only be amended with the prior approval of the holders of the first preference shares, in addition to any other approvals required by the *Corporations Act* (Newfoundland and Labrador) or any other statutory provisions of like or similar effect in force from time to time.

The approval of the holders of the first preference shares with respect to any and all matters may be given by at least two-thirds of the votes cast at a meeting of the holders of the first preference shares duly called for that purpose.

First Preference Shares Authorized and Outstanding

The following table summarizes the series of first preference shares as of February 11, 2021.

	Authorized	Issued and Outstanding	Initial Yield *(%)*	Annual Dividend *($)* [1]	Reset Dividend Yield *(%)*	Redemption and/or Conversion Option Date [2]	Redemption Value *($)*	Right to Convert on a One for One Basis
Perpetual Fixed Rate								
Series F	5,000,000	5,000,000	4.90	1.2250	—	Currently Redeemable	25.00	—
Series J [3]	8,000,000	8,000,000	4.75	1.1875	—	Currently Redeemable	25.25	—
Fixed Rate Reset [4]								
Series G	9,200,000	9,200,000	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H [5][6]	10,000,000	7,665,082	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K [5]	12,000,000	10,000,000	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M [5]	24,000,000	24,000,000	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating Rate Reset [5][7]								
Series I	10,000,000	2,334,918	2.10	—	1.45	June 1, 2025	25.00	Series H
Series L	12,000,000	—	—	—	—	—	—	Series K
Series N	24,000,000	—	—	—	—	—	—	Series M

[1] *Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend, if, as and when declared by the Board, 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 are redeemable as of December 1, 2021 and thereafter at $25.00 per share.*

[4] *On the redemption and/or conversion option date, and on 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 H was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*

[7] *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 June 1, 2020, 267,341 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I, and 907,577 First Preference Shares, Series I were converted on a one-for-one basis into First Preference Shares Series H.

Second Preference Shares

The rights, privileges, conditions and restrictions attaching to the second preference shares are substantially identical to those attaching to the first preference shares, except that the second preference shares are junior to the first preference shares with respect to the payment of dividends, repayment of capital and the distribution of assets of Fortis in the event of a liquidation, dissolution or winding up of Fortis.

The specific terms of the second preference shares, including the currency in which second preference shares may be purchased and redeemed and the currency in which any dividend is payable, if other than Canadian dollars, and the extent to which the general terms described in herein apply to those second preference shares, will be as set forth in the applicable articles of amendment of Fortis relating to such series.

As of February 11, 2021, there were no second preference shares issued and outstanding.

EXHIBIT B: MARKET FOR SECURITIES

Common Shares

The common shares are traded on the TSX in Canada, and on the NYSE in the US, in each case under the symbol FTS. The following table sets forth the reported high and low trading prices and trading volumes, on a monthly basis for the year ended December 31, 2020, for the common shares on the TSX and NYSE in Canadian Dollars and US Dollars, respectively.

2020 Trading Prices and Volumes – Common Shares						
	TSX			NYSE		
Month	**High** *($)*	**Low** *($)*	**Volume**	**High** *(US$)*	**Low** *(US$)*	**Volume**
January	58.53	53.23	28,162,388	44.49	41.00	7,129,151
February	59.28	54.02	29,749,946	44.72	40.16	6,769,689
March	58.81	41.52	70,060,854	43.89	28.59	21,903,132
April	56.46	50.21	43,128,034	40.45	35.45	13,852,377
May	54.87	49.87	47,773,297	39.02	35.53	9,893,976
June	54.63	50.06	32,723,978	40.76	36.64	8,778,081
July	54.89	50.95	26,455,647	40.88	37.55	7,308,449
August	55.25	51.94	29,087,042	41.20	39.62	7,501,978
September	55.00	51.30	30,618,813	41.19	38.73	7,165,906
October	56.16	52.40	30,823,383	42.47	39.32	5,481,500
November	56.34	51.96	40,244,074	43.49	39.53	8,477,013
December	53.76	51.10	32,629,574	42.17	39.50	6,763,915

Preference Shares

The First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis are listed on the TSX under the symbols FTS.PR.F; FTS.PR.G; FTS.PR.H; FTS.PR.I; FTS.PR.J; FTS.PR.K and FTS.PR.M, respectively.

The following tables set forth the reported high and low trading prices and volumes for the First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M on a monthly basis for the year ended December 31, 2020.

2020 Trading Prices and Volumes – First Preference Shares						
	First Preference Shares, Series F			First Preference Shares, Series G		
Month	**High** *($)*	**Low** *($)*	**Volume**	**High** *($)*	**Low** *($)*	**Volume**
January	24.19	23.62	77,489	17.74	16.78	334,760
February	24.30	23.24	42,563	17.51	16.16	113,369
March	23.95	18.96	95,026	16.31	11.11	297,277
April	23.10	20.37	38,451	15.67	13.40	158,094
May	23.33	22.05	43,997	14.61	13.58	143,485
June	23.65	22.45	55,503	14.60	13.83	119,970
July	24.50	23.58	46,797	16.62	13.95	118,575
August	24.10	23.57	83,306	15.75	14.75	191,711
September	25.19	23.69	503,275	15.89	15.02	242,547
October	26.51	24.80	268,263	16.23	15.34	129,750
November	25.70	24.80	29,800	17.00	15.96	111,071
December	25.45	25.00	32,236	16.83	16.27	125,012

	First Preference Shares, Series H			First Preference Shares, Series I		
Month	**High** *($)*	**Low** *($)*	**Volume**	**High** *($)*	**Low** *($)*	**Volume**
January	13.88	12.88	115,276	13.65	12.80	9,123
February	13.47	11.99	108,214	13.40	11.99	24,979
March	12.01	7.48	294,824	12.11	7.71	49,701
April	10.85	9.61	173,256	10.50	9.00	55,117
May	9.99	9.34	85,007	10.01	9.10	58,793
June	9.95	9.16	66,803	9.59	8.95	91,680
July	11.18	9.55	104,299	9.95	8.91	43,239
August	10.84	10.10	119,067	10.25	9.65	20,372
September	10.74	10.20	94,257	10.30	9.99	53,357
October	10.70	10.16	140,485	10.42	10.00	18,278
November	11.10	10.10	123,715	10.60	9.99	50,935
December	12.22	10.92	120,688	11.34	10.80	49,137

	First Preference Shares, Series J			First Preference Shares, Series K		
Month	**High** *($)*	**Low** *($)*	**Volume**	**High** *($)*	**Low** *($)*	**Volume**
January	22.92	22.31	349,242	16.95	16.00	166,582
February	23.45	22.35	176,650	16.83	15.55	170,052
March	22.95	17.77	191,724	15.60	10.00	188,053
April	22.22	19.32	109,252	14.16	12.75	364,109
May	22.49	21.50	119,188	14.06	12.95	160,251
June	22.65	21.80	81,518	14.15	13.19	249,878
July	23.20	22.20	107,069	15.79	13.28	149,365
August	23.10	22.61	78,263	15.09	14.03	112,132
September	24.77	22.90	82,101	15.12	14.45	120,530
October	25.00	23.76	245,504	15.45	14.62	73,351
November	24.67	23.99	133,621	15.87	15.00	88,164
December	24.61	24.16	147,781	16.40	15.72	97,530

	First Preference Shares, Series M		
Month	**High** *($)*	**Low** *($)*	**Volume**
January	18.39	17.25	623,228
February	18.42	16.46	221,623
March	16.69	11.98	599,336
April	15.99	14.17	286,909
May	15.71	14.68	512,391
June	15.54	14.70	264,972
July	17.38	14.99	382,513
August	17.10	16.24	278,654
September	17.20	16.76	275,954
October	17.70	17.00	549,645
November	18.57	17.39	134,214
December	18.85	18.02	205,217

EXHIBIT C: AUDIT COMMITTEE MANDATE

1.0 PURPOSE AND AUTHORITY

1.1 The purpose of the Committee is to advise and assist the Board in fulfilling its oversight responsibilities relating to, among other things:

a. the integrity of the Corporation's financial statements, financial disclosures and internal controls over financial reporting and disclosure controls and procedures;

b. the Corporation's compliance with related legal and regulatory requirements;

c. the qualifications, independence and performance of the Independent Auditor and Internal Auditor, together with the compensation of the Independent Auditor;

d. the Corporation's ERM Program and the management and mitigation of significant risks identified thereunder;

e. the related policies of the Corporation set out herein; and

f. other matters set out herein or otherwise delegated to the Committee by the Board.

1.2 Consistent with this purpose, the Committee should encourage continuous improvement of, and foster adherence to, the Corporation's policies, procedures and practices at all levels. The Committee should also provide for open communication among the Independent Auditor, the Internal Auditor, Management and the Board.

1.3 To perform its duties and responsibilities, the Committee has the authority to: (i) conduct investigations into any matters within its scope of responsibility; (ii) have unrestricted access to information, management and employees and books and records of the Corporation and its affiliates; and (iii) directly access and communicate with the Independent Auditor and Internal Auditor.

2.0 DEFINITIONS

2.1 In this Mandate:

a. "**Board**" means the board of directors of the Corporation;

b. "**Chair**" means the Chair of the Committee;

c. "**Committee**" means the audit committee of the Board;

d. "**Core Audit Services**" means services necessary to: (i) audit the Corporation's annual consolidated or non-consolidated financial statements; (ii) review the Corporation's interim condensed consolidated financial statements; and (iii) audit internal controls over financial reporting in accordance with the requirements of the Sarbanes Oxley Act of 2002 and all applicable laws, regulations and professional standards;

e. "**Corporation**" means Fortis Inc.;

f. "**CPAB**" means the Canadian Public Accountability Board or its successor;

g. "**Director**" means a member of the Board;

h. "**ERM Program**" means the Corporation's Enterprise Risk Management Program that incorporates an effective risk management framework to identify, evaluate, manage, monitor and communicate key corporate risks;

i. "**Financial Expert**" means an "audit committee financial expert" as defined in Item 407(d)(5) of SEC Regulation S-K;

j. "**Financially Literate**" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

k. "**Governance and Sustainability Committee**" means the governance and sustainability committee of the Board;

l. "**Independent**" means, in the context of a Member and in accordance with all applicable laws and stock exchange requirements, being free from any direct or indirect material relationship with the Corporation and its subsidiaries which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment;

m. "**Independent Auditor**" means the firm of chartered professional accountants, registered with the CPAB and the PCAOB, and appointed by the shareholders to act as external auditor;

n. "**Internal Auditor**" means the person(s) employed or engaged by the Corporation to perform the internal audit function of the Corporation;

o. "**Management**" means the senior officers of the Corporation;

p. "**Mandate**" means this mandate of the Committee;

q. "**MD&A**" means the Corporation's management discussion and analysis prepared in accordance with the requirements of National Instrument 51-102F1 and the SEC in respect of the Corporation's annual consolidated and interim condensed consolidated financial statements;

r. "**Member**" means a Director appointed to the Committee;

s. "**NYSE**" means the New York Stock Exchange;

t. "**PCAOB**" means the Public Company Accounting Oversight Board or its successor;

u. "**Related Party Transactions**" means those transactions required to be disclosed under Items 404(a) and 404(b) of SEC Regulation S-K and required to be evaluated by an appropriate group within the Corporation pursuant to Section 314.00 of the NYSE Listed Company Manual and all applicable laws and stock exchange requirements which include, without limitation, transactions between: (i) executive officers, directors, principal shareholders or their immediate family members; and (ii) the Corporation; and

v. "**SEC**" means the United States Securities and Exchange Commission.

3.0 ESTABLISHMENT AND COMPOSITION OF COMMITTEE

3.1 The Committee shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate. No Member may be a member of Management or an employee of the Corporation or of any affiliate of the Corporation. The Board shall appoint to the Committee at least one (1) Director who is a Financial Expert.

3.2 Members shall be appointed annually by the Board, or at other times as may be necessary, provided, however, that if the appointment of Members is not so made, each Director then serving as a Member shall continue as a Member until he or she resigns or is removed or his or her successor is appointed.

3.3 The Board may appoint a Member to fill a vacancy which occurs on the Committee between annual elections of Directors. If a vacancy exists on the Committee, the remaining Members shall exercise all of the powers of the Committee so long as at least three (3) Members remain in office.

3.4 Any Member may be removed from the Committee or replaced by a resolution of the Board.

3.5 No Member shall serve on more than three (3) public company audit committees (inclusive of the Corporation) without the prior approval of the Board.

3.6 The Board shall appoint a Chair on the recommendation of the Corporation's Governance and Sustainability Committee, or such other committee as the Board may authorize, provided, however, that if the appointment of the Chair is not so made, the Director who is then serving as Chair shall continue as Chair until his or her successor is appointed. The Board shall periodically rotate the Chair and shall make reasonable efforts to rotate the Chair every four (4) years.

4.0 COMMITTEE MEETINGS

4.1 The Committee shall meet at least quarterly and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of: (i) the Chair; (ii) any two Members; or (iii) the Independent Auditor.

4.2 The Chief Executive Officer, the Chief Financial Officer, the Independent Auditor and the Internal Auditor shall receive notice of and, unless otherwise determined by the Chair, shall be entitled to attend all meetings of the Committee. For clarity, the Independent Auditor must attend the Committee meetings at which the Corporation's annual audited consolidated and non-consolidated financial statements and interim unaudited condensed consolidated financial statements are reviewed.

4.3 A quorum at any meeting of the Committee shall be three (3) Members.

4.4 Each Member shall have the right to vote on matters that come before the Committee.

4.5 Any matter to be determined by the Committee shall be decided by a majority of votes cast at a meeting of the Committee at which such matter is considered. Actions of the Committee may also be taken by an instrument or instruments in writing signed by all of the Members, and such actions shall be effective as though they had been decided by a majority of votes cast at a meeting of the Committee called for such purpose.

4.6 The Chair shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their number to act as chair of the meeting.

4.7 Unless otherwise determined by the Chair, the Corporate Secretary of the Corporation shall act as secretary of all meetings of the Committee.

4.8 The Committee shall periodically meet separately with Management, the Internal Auditor and the Independent Auditor to discuss any matters that the Committee or any of these persons or firms believes should be discussed privately. The Committee shall conduct *in camera* sessions without Management present at each meeting of the Committee.

4.9 The Committee may invite any Directors, officers or employees of the Corporation or any other person to attend the meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

4.10 Subject to section 5.4, the Committee may delegate authority to individual Members or subcommittees, if deemed appropriate.

5.0 DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

A. Independent Auditor

5.1 In consultation and coordination with the subsidiary audit committees, the Committee shall be directly responsible for the selection and appointment (through a recommendation to the Board for the appointment by the shareholders), compensation and retention of the Independent Auditor.

5.2 The Committee shall oversee the work of the Independent Auditor in connection with the Core Audit Services and any other services performed for the Corporation. The Independent Auditor shall report directly to the Committee and the Committee has the authority to communicate directly with the Independent Auditor.

5.3 The Committee shall oversee the resolution of any disagreements between Management and the Independent Auditor. The Committee shall discuss with the Independent Auditor the matters required to be discussed under PCAOB Auditing Standard No. 1301 relating to the conduct of the audit, including any problems or difficulties encountered and Management's responses thereto and any restrictions on the scope of activities or access to requested information.

5.4 The Committee shall pre-approve all services performed by the Independent Auditor in accordance with the Corporation's Pre-Approval Policy for Independent Auditor Services. For any service, other than Core Audit Services, requiring specific pre-approval in accordance with such policy, the Committee may delegate pre-approval authority to one or more of its Members. Currently, pre-approval authority in this regard has been delegated to the Chair or, in that person's absence, the Chair of the Board who is a Member. Delegates must report all pre-approval decisions to the Committee at the next scheduled meeting.

5.5 The Committee shall annually obtain and review a report from the Independent Auditor delineating all relationships between the Independent Auditor and the Corporation and its subsidiaries in accordance with Item 407(d) of SEC Regulation S-K and Section 303A.07 of the NYSE Listed Company Manual and addressing the matters set forth in PCAOB Rule 3526 and all applicable laws and stock exchange requirements and any other applicable regulations and professional standards. The Committee shall use reasonable efforts, including discussion with the Independent Auditor, to satisfy itself as to the Independent Auditor's independence in accordance with Canadian generally accepted auditing standards and PCAOB standards, the applicable requirements and interpretative guidance of SEC Regulation S-X and any other applicable regulations and professional standards. The Committee shall discuss any potential independence issues with the Board and recommend any commensurate action that the Committee deems appropriate.

5.6 The Committee shall review and evaluate the qualifications, independence and performance of the Independent Auditor and its lead engagement partner. Without limiting the foregoing, the Committee shall:

a. review and discuss with Management and separately with the Independent Auditor the results of the Corporation's annual Independent Auditor assessment process; and

b. at least annually, obtain and review a report from the Independent Auditor describing the firm's internal quality control processes and procedures, including any material issues raised by the most recent internal quality control review or peer review, or by any inquiry or investigation by governmental or professional authorities (including without limitation the PCAOB and the CPAB) within the preceding five (5) years with respect to independent audits carried out by the Independent Auditor, and any steps taken to address such issues.

The Committee shall discuss any material issues identified with the Board and recommend any commensurate action that the Committee deems appropriate.

5.7 The Committee shall ensure the rotation of the audit partner(s) as required by applicable law and consider the need for rotation of the Independent Auditor.

5.8 The Committee shall meet with the Independent Auditor prior to the audit to discuss the planning and staffing of the audit, including the general approach, scope, areas subject to significant risk of material misstatement, estimated fees and other terms of engagement.

B. Financial Reporting

5.9 In consultation with Management, the Independent Auditor and the Internal Auditor, the Committee shall review and satisfy itself as to: (i) the integrity of the Corporation's internal and external financial reporting processes; (ii) the adequacy and effectiveness of the Corporation's disclosure controls and procedures (including those pertaining to the review of disclosure containing financial information extracted or derived from the Corporation's financial statements) and internal controls over financial reporting; and (iii) the competence of the Corporation's personnel responsible for accounting and financial reporting. Without limiting the generality of the foregoing, the Committee shall receive and review:

a. reports regarding: (i) critical accounting estimates, policies and practices; (ii) goodwill impairment testing; (iii) derivatives and hedges; (iv) any reserves, accruals, provisions and estimates that may have a material effect on the Corporation's financial statements; (v) any *pro forma*, adjusted or restated financial information, or forecasts, or projections; and (vii) the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements, on the Corporation's financial statements;

b. analyses by Management and the Independent Auditor regarding significant financial reporting issues and judgments made in connection with the preparation of the Corporation's consolidated financial statements including: (i) alternative treatments of financial information within generally accepted accounting principles related to material matters that have been discussed with Management, their ramifications and the treatment preferred by the Independent Auditor; (ii) major issues regarding auditing and accounting principles and presentations, including significant changes in the selection or application of auditing and accounting principles; and (iii) major issues regarding the adequacy of the Corporation's internal controls over financial reporting and disclosure controls and procedures and any specific audit steps adopted in light of material weaknesses or significant deficiencies in such controls; and

c. other material written communication between Management and the Independent Auditor.

5.10 The Committee shall, prior to external release, if applicable, review and discuss with Management and the Independent Auditor, and with others as it deems appropriate:

a. the Corporation's annual audited consolidated and non-consolidated financial statements and interim unaudited condensed consolidated financial statements and the Independent Auditor's related attestation reports, as well as any related MD&As;

b. Management's report and the Independent Auditor's audit report on internal controls over financial reporting;

c. significant reports or summaries thereof pertaining to the Corporation's processes for compliance with the requirements of the Sarbanes Oxley Act of 2002 with respect to internal controls over financial reporting;

d. the Independent Auditor's quarterly review reports and annual audit results report summarizing the scope, status, results and recommendations of the quarterly reviews of the Corporation's interim condensed consolidated financial statements and of the audit of the Corporation's annual consolidated financial statements and related audit of internal controls over financial reporting, and also containing at least: (i) the communications with respect thereto between the Independent Auditor and the Committee required by PCAOB Auditing Standard No. 1301 and any other applicable regulations and professional standards, including without limitation schedules of corrected and uncorrected account and disclosure misstatements and significant deficiencies and material weaknesses in internal controls; (ii) the (at least) annual independence communication required by PCAOB Rule 3526; (iii) the Management representation letter; and (iv) the documentation and communication required

quarterly from the Independent Auditor under the Corporation's Pre-Approval Policy for Independent Auditor Services;

e. the report to shareholders contained in the Corporation's annual report; and

f. any other document that the Committee determines should be reviewed and discussed with Management and the Independent Auditor or for which a legal or regulatory requirement in that regard exists.

5.11 The Committee shall, prior to external release, review and discuss with Management and with others as it deems appropriate, the financial information to be disclosed in the Corporation's interim and annual earnings releases or other news releases.

5.12 The Committee shall recommend the Corporation's annual audited consolidated financial statements together with the Independent Auditor's audit report thereon and on internal controls over financial reporting, Management's report on internal controls over financial reporting and disclosure controls and procedures, MD&As, earnings releases, and Reports to Shareholders for approval by the Board and subsequent external release, as well as inclusion of the noted financial statements in the Corporation's annual reports on Form 40-F. The Committee shall approve the external release of the Corporation's interim unaudited condensed consolidated financial statements and related interim MD&As and earnings releases on behalf of the Board.

5.13 The Committee shall, prior to external release, review and discuss with Management and with others as it deems appropriate, and recommend for approval by the Board:

a. any future oriented financial information, financial outlooks, and earnings or dividend guidance to be provided by the Corporation;

b. the Annual Information Form and Management Information Circular to be filed by the Corporation;

c. any prospectus or other offering documents and documents related thereto for the issuance of securities by the Corporation; and

d. other disclosure documents to be released publicly by the Corporation containing or derived from financial information.

5.14 The Committee shall review, discuss with Management and with others as it deems appropriate, the disclosures made by the Chief Executive Officer and Chief Financial Officer of the Corporation pursuant to their certification of the Corporation's annual and quarterly reports regarding significant deficiencies or material weaknesses in the design or operation of internal controls over financial reporting and any alleged fraud involving Management or other employees.

5.15 The Committee shall use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing, capital and tax structures.

5.16 The Committee shall review, discuss with Management and with others as it deems appropriate, financial information provided to analysts and ratings agencies. Such discussions may be in general terms (i.e. discussion of the types of information to be disclosed and the types of presentations to be made) and need not occur in advance of each release of information.

5.17 The Committee shall prepare, or cause to be prepared, any reports of the Committee required to be included in the Corporation's public disclosures or otherwise required by applicable laws.

5.18 The Committee shall review, discuss with Management and with others as it deems appropriate, and approve all Related Party Transactions and the disclosure thereof.

C. Internal Audit

5.19 The Committee shall be responsible for the appointment and oversight of the Internal Auditor in accordance with the Policy on the Role of the Internal Audit Function and has the authority to communicate directly with the Internal Auditor.

5.20 The Committee shall review, discuss with the Internal Auditor and others as it deems appropriate and approve the annual internal audit plan.

5.21 The Committee shall review and discuss with Management and the Internal Auditor and others as it deems appropriate the quarterly internal audit reports prepared for the Committee (which shall incorporate all significant activities of the internal audit function for the quarter) and any Management responses thereto.

5.22 The Committee shall periodically discuss with the Internal Auditor any significant difficulties, disagreements with Management, or scope restrictions encountered in the course of carrying out the work of the internal audit function.

5.23 The Committee shall periodically discuss with the Internal Auditor the internal audit function's responsibility, budget and staffing.

5.24 The Committee shall satisfy itself as to the performance of the internal audit function and the integrity and qualifications of its staff.

D. Risk Management and Other

5.25 The Committee shall be responsible for the oversight of and reporting to the Board in respect of the ERM Program.

5.26 The Committee shall review and discuss with Management, the Internal Auditor and others as it deems appropriate Management's report regarding identifying, assessing, managing and mitigating significant risks and related matters identified pursuant to the ERM Program.

5.27 The Committee shall review and discuss with Management and others as it deems appropriate the quarterly report prepared by Management regarding significant litigation and other material legal matters that could have a significant impact on the Corporation or its financial statements.

5.28 The Committee shall be responsible for the oversight of the Corporation's insurance programs, any renewals or replacements thereof, including in respect of directors' and officers' insurance and indemnification of Directors.

E. Policies and Mandate

5.29 The Committee is responsible for the oversight of the following policies:

a. Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing (Whistleblower Policy), including overseeing procedures for the receipt, retention, and treatment of complaints regarding accounting, internal controls, or auditing matters as well as procedures for confidential, anonymous submissions by employees regarding questionable accounting or auditing matters as required by applicable law;

b. Derivative Instruments and Hedging Policy;

c. Pre-Approval Policy for Independent Auditor Services;

d. Guidelines for Hiring Employees or Former Employees of the Independent Auditor;

e. Policy on the Role of the Internal Audit Function;

f. Disclosure Policy; and

g. other policies that may be established from time-to-time regarding accounting, financial reporting, disclosure controls and procedures, internal controls over financial reporting, oversight of the external audit of the Corporation's financial statements, and oversight of the internal audit function.

5.30 The Committee shall periodically review this Mandate and the policies in Section 5.29 and recommend any necessary amendments to the Governance and Sustainability Committee for consideration and recommendation to the Board for approval, as deemed appropriate.

6.0 REPORTING

6.1 The Chair, or another designated Member, shall report to the Board at each regular meeting on those matters that were dealt with by the Committee since the last regular meeting of the Board.

7.0 REMUNERATION OF MEMBERS

7.1 Members and the Chair shall receive such remuneration for their service on the Committee as the Board may determine from time to time, having considered the recommendation of the Governance and Sustainability Committee.

8.0 GENERAL

8.1 This Mandate shall be posted on the Corporation's corporate website at www.fortisinc.com.

8.2 The Committee shall annually review its own effectiveness and performance.

8.3 The Committee shall perform any other activities consistent with this Mandate, the Corporation's by-laws and applicable laws, that the Board or Committee determines are necessary or appropriate.

8.4 The Committee may, in its discretion and in circumstances that it considers appropriate, obtain advice and assistance from outside legal, accounting and other advisors and approve the engagement by the Committee or any Member of outside advisors or persons having special expertise, all at the expense of the Corporation. The Corporation shall provide appropriate compensation, as determined by the Committee, for the Independent Auditor, to any independent counsel or other advisors that the Committee chooses to engage, and for payment of ordinary administrative expenses of the Committee that are necessary and appropriate in carrying out its duties and responsibilities.

8.5 The Committee is not responsible for certifying the accuracy or completeness of the Corporation's financial statements or their presentation in accordance with generally accepted accounting principles, or for guaranteeing the accuracy of the attestation reports of the Independent Auditor. The fundamental responsibility for the Corporation's financial statements and reporting, internal controls over financial reporting and disclosure controls and processes rests with Management and, in accordance with its professional responsibilities, the Independent Auditor. Nothing in this Mandate is intended to modify or augment the obligations of the Corporation or the fiduciary duties of the members of the Committee or the Board under applicable laws.

EXHIBIT D: MATERIAL CONTRACTS

The following are the material contracts of Fortis filed on SEDAR and EDGAR during 2020 or which were entered into prior to 2020 and are still in effect. Requests for additional copies of these material contracts should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). All such contracts are also available under the Corporation's profile at www.sedar.com and www.sec.gov.

Revolving Credit Facility

Fortis is a party to a Third Amended and Restated Credit Facility dated July 31, 2017, with The Bank of Nova Scotia as underwriter, sole lead arranger and bookrunner and administrative agent and Canadian Imperial Bank of Commerce and Royal Bank of Canada as co-syndication agents, and the lenders party thereto from time to time, as amended by the First Amending Agreement dated May 11, 2018 and the Second Amending Agreement dated May 13, 2019, each between Fortis, The Bank of Nova Scotia and the lenders named therein. The Third Amended and Restated Credit Facility is a $1.3 billion unsecured committed revolving credit facility and contains the terms and conditions upon which such credit is available to Fortis during the duration of the facility. The Third Amended and Restated Credit Facility contains customary representations and warranties, affirmative and negative covenants and events of default. Customary fees are payable by Fortis in respect of the facility and amounts outstanding under the facility bear interest at market rates.

Amended and Restated Shareholders' Agreement

On January 28, 2021, ITC Investment Holdings, ITC Holdings, FortisUS and Eiffel Investment, an affiliate of GIC, entered into an Amended and Restated Shareholders' Agreement, amending the shareholders' agreement among the parties originally entered into on October 14, 2016. The Amended and Restated Shareholders' Agreement governs the rights of the parties in their respective capacities as direct or indirect shareholders of ITC Holdings.

Under the terms of the Amended and Restated Shareholders' Agreement, Eiffel Investment has certain minority approval rights relating to ITC Investment Holdings and ITC Holdings which depend on (x) whether Eiffel Investment is a holder of Class A common stock or Class B non-voting common stock at the relevant time and (y) the satisfaction by Eiffel Investment of certain ownership thresholds with respect to ITC Investment Holdings. The minority approval rights available to Eiffel Investment contingent on its ITC Investment Holdings share class and percentage ownership include rights with respect to: (i) amendments to charter documents; (ii) changes in board size; (iii) issuances of equity; (iv) business combinations that would impact Eiffel Investment differently than other shareholders; (v) insolvency; (vi) certain acquisitions of, investments in, or joint ventures relating to non-core assets, or certain material sales or dispositions of core assets; (vii) in limited circumstances, the incurrence of indebtedness by ITC Investment Holdings, ITC Holdings or its subsidiaries or the taking of certain actions that would reasonably be expected to result in the long-term unsecured indebtedness of ITC Investment Holdings, ITC Holdings and its subsidiaries being rated below investment grade; (viii) actions that would cause a ratio of ITC Holding's cash flow to debt to exceed an agreed targeted threshold; (ix) limitations on corporate overhead costs paid by ITC Holdings to Fortis; and (x) expansion of the core business outside ITC Holdings' current regulatory jurisdictions. The Amended and Restated Shareholders' Agreement also provides for a dividend policy, which can be amended only with the approval of all the independent directors of ITC Investment Holdings.

Indenture and First Supplemental Indenture

On October 4, 2016, Fortis entered into an Indenture and a First Supplement thereto with The Bank of New York Mellon, as US trustee, and BNY Trust Company of Canada, as Canadian co-trustee. The Indenture and the First Supplement set forth the terms of the Corporation's outstanding US$1.1 billion aggregate principal amount of 3.055% Unsecured Notes due 2026. The Indenture contains customary covenants, events of default and rights for the benefit of security holders and the trustees. An unlimited amount of debt securities may be issued under the Indenture, which is governed by the laws of the State of New York.

Exhibit 99.2

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2020 and 2019

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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, 2020, 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, 2020, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2020 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, 2020. Deloitte LLP issued an unqualified opinion for both audits.

February 11, 2021

/s/ David G. Hutchens

David G. Hutchens
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, 2020 and 2019, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, 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, 2020, 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 11, 2021, 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 12 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 more recently acquired reporting units included the following:

- 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 8 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 to 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 11, 2021

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, 2020, 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, 2020, 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 of and for the year ended December 31, 2020, of the Corporation and our report dated February 11, 2021, 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 11, 2021

FORTIS INC.

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

	2020	2019
ASSETS		
Current assets		
Cash and cash equivalents	**$ 249**	$ 370
Accounts receivable and other current assets (Note 6)	**1,369**	1,297
Prepaid expenses	**102**	88
Inventories (Note 7)	**422**	394
Regulatory assets (Note 8)	**470**	425
Total current assets	**2,612**	2,574
Other assets (Note 9)	**670**	620
Regulatory assets (Note 8)	**3,118**	2,958
Property, plant and equipment, net (Note 10)	**35,998**	33,988
Intangible assets, net (Note 11)	**1,291**	1,260
Goodwill (Note 12)	**11,792**	12,004
Total assets	**$ 55,481**	$ 53,404
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 132**	$ 512
Accounts payable and other current liabilities (Note 13)	**2,321**	2,402
Regulatory liabilities (Note 8)	**441**	572
Current installments of long-term debt (Note 14)	**1,254**	690
Total current liabilities	**4,148**	4,176
Other liabilities (Note 16)	**1,599**	1,446
Regulatory liabilities (Note 8)	**2,662**	2,786
Deferred income taxes (Note 24)	**3,344**	2,969
Long-term debt (Note 14)	**23,113**	21,501
Finance leases (Note 15)	**331**	413
Total liabilities	**35,197**	33,291
Commitments and contingencies (Note 28)		
Equity		
Common shares (Note 17) [(1)]	**13,819**	13,645
Preference shares (Note 19)	**1,623**	1,623
Additional paid-in capital	**11**	11
Accumulated other comprehensive income (Note 20)	**34**	336
Retained earnings	**3,210**	2,916
Shareholders' equity	**18,697**	18,531
Non-controlling interests	**1,587**	1,582
Total equity	**20,284**	20,113
Total liabilities and equity	**$ 55,481**	$ 53,404

[(1)] *No par value. Unlimited authorized shares. 466.8 million and 463.3 million issued and outstanding as at December 31, 2020 and 2019, 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)

		2020		2019
Revenue (Note 5)	**$**	**8,935**	$	8,783
Expenses				
Energy supply costs		**2,562**		2,520
Operating expenses		**2,437**		2,452
Depreciation and amortization		**1,428**		1,350
Total expenses		**6,427**		6,322
Gain on disposition (Note 22)		**—**		577
Operating income		**2,508**		3,038
Other income, net (Note 23)		**154**		138
Finance charges		**1,042**		1,035
Earnings before income tax expense		**1,620**		2,141
Income tax expense (Note 24)		**231**		289
Net earnings	**$**	**1,389**	$	1,852
Net earnings attributable to:				
Non-controlling interests	**$**	**115**	$	130
Preference equity shareholders		**65**		67
Common equity shareholders		**1,209**		1,655
	$	**1,389**	$	1,852
Earnings per common share (Note 18)				
Basic	**$**	**2.60**	$	3.79
Diluted	**$**	**2.60**	$	3.78

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)

		2020		2019
Net earnings	**$**	**1,389**	$	1,852
Other comprehensive loss				
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $8 million and $13 million, respectively		**(311)**		(660)
Other, net of income tax recovery of $9 million and $5 million, respectively		**(27)**		(7)
		(338)		(667)
Comprehensive income	**$**	**1,051**	$	1,185
Comprehensive income attributable to:				
Non-controlling interests	**$**	**79**	$	55
Preference equity shareholders		**65**		67
Common equity shareholders		**907**		1,063
	$	**1,051**	$	1,185

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)

	2020	2019
Operating activities		
Net earnings	**$ 1,389**	$ 1,852
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,282**	1,199
Amortization - intangible assets	**131**	125
Amortization - other	**15**	26
Deferred income tax expense (Note 24)	**226**	247
Equity component, allowance for funds used during construction (Note 23)	**(78)**	(74)
Gain on disposition (Note 22)	**—**	(583)
Other	**165**	145
Change in long-term regulatory assets and liabilities	**5**	(106)
Change in working capital (Note 26)	**(434)**	(168)
Cash from operating activities	**2,701**	2,663
Investing activities		
Capital expenditures - property, plant and equipment	**(3,857)**	(3,499)
Capital expenditures - intangible assets	**(182)**	(221)
Contributions in aid of construction	**68**	102
Proceeds on disposition (Note 22)	**—**	995
Other	**(161)**	(145)
Cash used in investing activities	**(4,132)**	(2,768)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,470**	937
Repayments of long-term debt, net of extinguishment costs, and finance leases	**(1,251)**	(1,676)
Borrowings under committed credit facilities	**5,648**	5,892
Repayments under committed credit facilities	**(5,299)**	(6,290)
Net change in short-term borrowings	**(413)**	472
Issue of common shares, net of costs, and dividends reinvested (Note 17)	**58**	1,442
Dividends		
Common shares, net of dividends reinvested	**(786)**	(494)
Preference shares	**(65)**	(67)
Subsidiary dividends paid to non-controlling interests	**(65)**	(73)
Other	**30**	11
Cash from financing activities	**1,327**	154
Effect of exchange rate changes on cash and cash equivalents	**(17)**	(26)
Change in cash and cash equivalents	**(121)**	23
Cash and change in cash associated with assets held for sale	**—**	15
Cash and cash equivalents, beginning of year	**370**	332
Cash and cash equivalents, end of year	**$ 249**	$ 370

Supplementary Cash Flow Information (Note 26)

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Changes in Equity
For the years ended December 31, 2020 and 2019
(in millions of Canadian dollars, except share numbers)

	Common Shares *(# millions)*	Common Shares *(Note 17)*	Preference Shares *(Note 19)*	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) *(Note 20)*	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2019	**463.3**	**$ 13,645**	**$ 1,623**	**$ 11**	**$ 336**	**$ 2,916**	**$ 1,582**	**$ 20,113**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,274**	**115**	**1,389**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(302)**	**—**	**(36)**	**(338)**
Common shares issued	**3.5**	**174**	**—**	**(3)**	**—**	**—**	**—**	**171**
Advances to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(13)**	**(13)**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(65)**	**(65)**
Dividends declared on common shares ($1.965 per share)	**—**	**—**	**—**	**—**	**—**	**(915)**	**—**	**(915)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(65)**	**—**	**(65)**
Other	**—**	**—**	**—**	**3**	**—**	**—**	**4**	**7**
As at December 31, 2020	**466.8**	**$ 13,819**	**$ 1,623**	**$ 11**	**$ 34**	**$ 3,210**	**$ 1,587**	**$ 20,284**
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
Advances to non-controlling interests	—	—	—	—	—	—	(8)	(8)
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(73)	(73)
Dividends declared on common shares ($1.855 per share)	—	—	—	—	—	(821)	—	(821)
Dividends on preference shares	—	—	—	—	—	(67)	—	(67)
Disposition (Note 22)	—	—	—	—	—	—	(318)	(318)
Other	—	—	—	5	—	—	3	8
As at December 31, 2019	463.3	$ 13,645	$ 1,623	$ 11	$ 336	$ 2,916	$ 1,582	$ 20,113

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

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

Regulated Utilities

ITC: 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 a19.9% 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: 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 3,233 megawatts ("MW"), including 54 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: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, provides 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: FortisBC Inc. is 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: Eastern Canadian and Caribbean utilities, 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"); 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").

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 130 MW. FortisOntario consists 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 to connect remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

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 consists 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: 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 generating 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.

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"). PBR mechanisms generally apply a formula that incorporates 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 8).

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE [1] (%) 2020	2019	Significant Features
ITC [2] [3]	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.63	Cost-based formula rates, with annual true-up mechanism [4] Incentive adders
TEP	Arizona Corporation Commission ("ACC") [5]	50.0	**9.75**	9.75	COS regulation Historical test year
	FERC [6]	54.0	**10.40**	10.40	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson [7]	New York State Public Service Commission ("PSC")	50.0	**8.80**	8.80	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	38.5	**8.75**	8.75	COS regulation with formula components and incentives [8]
FortisBC Electric	BCUC	40.0	**9.15**	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**8.50**	8.50	PBR [9]
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.50**	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	**9.35**	9.35	COS regulation Future test year
FortisOntario [10]	Ontario Energy Board	40.0	**8.52-9.30**	8.78-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [11]	Utility Regulation and Competition Office	N/A	**6.75-8.75**	7.50-9.50	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI [12]	Government of the Turks and Caicos Islands	N/A	**15.00-17.50**	15.00-17.50	COS regulation Historical test year

[1] ROA for Caribbean Utilities and FortisTCI
[2] Includes the allowed common equity and base ROE plus incentive adders for ITCTransmission, METC, and ITC Midwest
[3] Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator ("MISO") region of 10.77%, up from 10.63% as set in the November 2019 decision. See "Significant Regulatory Developments" below
[4] Annual true-up reflected in rates within a two-year period
[5] Effective January 1, 2021, 53% allowed common equity and 9.15% ROE with 0.20% return on the fair value increment. See "COVID-19 Pandemic Impacts - Delayed and Postponed Regulatory Proceedings" below
[6] Approved effective August 1, 2019, subject to refund following hearing and settlement procedures. As at December 31, 2020, $19 million (2019 - $5 million) has been reserved as a regulatory liability
[7] Pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect a capital structure of 48%, 49% and 50% common equity as of July 1, 2018, 2019 and 2020, respectively. See "COVID-19 Pandemic Impacts - Delayed and Postponed Regulatory Proceedings" below
[8] Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below
[9] FortisAlberta is subject to PBR including mechanisms for flow-through costs and capital expenditures not otherwise recovered through customer rates. FortisAlberta's current PBR term expires as of December 31, 2022
[10] Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033
[11] 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
[12] Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037

COVID-19 Pandemic Impacts
The novel coronavirus ("COVID-19") pandemic resulted in several customer relief initiatives as well as the delay and postponement of several regulatory proceedings in 2020, as described below. The Corporation's significant regulatory proceedings, including TEP's general rate application as well as FortisAlberta's 2021 generic cost of capital ("GCOC") and Alberta Electric System Operator ("AESO") customer contribution proceedings, were concluded by the end of 2020.

Customer Relief Initiatives

UNS Energy
Pursuant to the ACC's approval of the utility's customer relief initiatives, TEP refunded to customers approximately $11 million of collected demand side management funds in excess of program costs.

In December 2020, the ACC enacted a bill credit and payment program for residential electric customers who are behind on their electric bills as a result of the COVID-19 pandemic, including automatic enrollment into an eight-month payment plan for qualified customers. TEP voluntarily created payment arrangements for commercial customers.

Central Hudson
In March 2020, as agreed with the PSC, Central Hudson postponed the collection in customer rates of approximately $8 million of deferred costs related mainly to environmental remediation until July 1, 2021.

FortisBC Energy and FortisBC Electric
In April 2020, pursuant to the BCUC's approval of the utilities' customer relief initiatives, FortisBC Energy and FortisBC Electric implemented three-month bill deferrals for certain customer classes, the repayment of which commenced in the third quarter of 2020. The BCUC also authorized the deferral of otherwise uncollectible revenue from customers, the recovery of which will be determined through a future rate filing once the financial impact of the pandemic is known.

Delayed and Postponed Regulatory Proceedings

UNS Energy
General Rate Application: TEP filed a rate application in April 2019 based on a 2018 test year. In December 2020 the ACC issued a rate order including new customer rates effective January 1, 2021 ("2020 Rate Order"). Provisions of the 2020 Rate Order include: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a rate base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River natural gas generation station Unit 2 and 10 natural gas reciprocating internal combustion engine units.

Central Hudson
2020 Rates: In June 2020, the PSC approved Central Hudson's request to postpone scheduled electric and gas delivery rate increases, reflecting an increase in the equity component of its capital structure from 49% to 50%, from July 1, 2020 to October 1, 2020. The deferred revenue associated with the delay is being collected over the nine-month period to June 30, 2021.

COVID-19 Proceeding: In June 2020, the PSC initiated a generic proceeding to identify and address the effects of the COVID-19 pandemic. The outcome of this proceeding and potential impacts, if any, are unknown at this time.

FortisAlberta
Generic Cost of Capital Proceeding: In December 2018, the AUC initiated a GCOC proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes were necessary for determining capital structure in years in which a ROE formula is in place. In October 2020, given the time that had passed since initiation of the proceeding and ongoing economic uncertainty, the AUC concluded the proceeding and set the ROE for 2021 at 8.5% using a capital structure of 37% common equity, consistent with 2020. In December 2020, the AUC initiated a new GCOC proceeding to establish the cost of capital parameters for 2022 and possibly one or more future years. This proceeding is expected to be ongoing throughout 2021.

Other Electric

Caribbean Utilities: In August 2020, the Utility Regulation and Competition Office approved the postponement of Caribbean Utilities' scheduled June 1, 2020 annual rate adjustment to January 1, 2021 to provide customer relief from the economic effects of the COVID-19 pandemic. The deferred revenue associated with the delay is being collected over a two-year period beginning January 2021.

FortisTCI: In February 2020, the Government of the Turks and Caicos Islands approved a 6.8% average increase in FortisTCI's electricity rates, effective April 1, 2020, including the recovery of hurricane-related costs incurred in 2017. In March 2020, to provide customer relief from the economic effects of the COVID-19 pandemic, the effective date was postponed and new rates became effective July 22, 2020.

FortisTCI sought regulatory approval to defer its incremental operating expenses associated with the COVID-19 pandemic. Approval was granted in December 2020 to allow the deferral of approximately $1.5 million in costs, to be amortized over the remaining 15-year life of FortisTCI's licence.

Significant Regulatory Developments

ITC

ROE Complaints: In May 2020, FERC issued an order on the rehearing of its November 2019 decision on the MISO transmission owner ROE complaints and set the base ROE for the periods from November 2013 through February 2015 and from September 2016 onward at 10.02%, up to a maximum of 12.62% with incentive adders. This represents an increase from the base ROE of 9.88%, up to a maximum of 12.24% with incentive adders, determined in FERC's November 2019 decision. Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the MISO region of 10.77%, up from 10.63% as set in the November 2019 decision.

Net regulatory liabilities of $6 million and $91 million were recorded at December 31, 2020 and 2019, respectively, reflecting: (i) the terms of the May 2020 and November 2019 decisions; and (ii) $42 million refunded to customers in 2020. The May 2020 FERC decision resulted in an increase in Fortis' net earnings of $29 million in 2020, including $27 million related to the reversal of liabilities established in prior periods (2019 - November 2019 FERC decision increased Fortis' net earnings by $63 million, including $83 million related to the reversal of liabilities established in prior periods).

Review of Transmission Incentives Policy: In March 2020, FERC issued a notice of proposed rulemaking ("NOPR") that included a proposal to update its transmission incentives policy for transmission owners, including ITC, to grant incentives to projects based upon benefits to customers regarding reliability and cost savings through the reduction of transmission congestion. FERC proposed total ROE incentives of up to 250 basis points that would not be limited by the upper end of the base ROE zone of reasonableness. The NOPR also proposed, among other things, to eliminate the ROE adder for independent transmission ownership, and to increase the ROE adder for regional transmission owner participation. Comments from stakeholders, including ITC, were provided to FERC through July 2020. The outcome of these proceedings may impact future incentive adders that are included in transmission rates charged by transmission owners, including ITC.

Central Hudson

General Rate Application: In August 2020, Central Hudson filed a rate application with the PSC requesting an increase in electric and natural gas delivery revenue of $44 million and $19 million, respectively, effective July 1, 2021. An order from the PSC is expected in 2021.

FortisBC Energy and FortisBC Electric

Multi-Year Rate Plan Applications: In June 2020, the BCUC issued a decision on FortisBC Energy's and FortisBC Electric's multi-year rate plan applications for 2020 to 2024. The decision sets the rate-setting framework for the five-year period, including: (i) the level of operation and maintenance expense and growth capital to be included in customer rates, indexed for inflation less a fixed productivity adjustment factor; (ii) a forecast approach to sustainment capital; (iii) an innovation fund recognizing the need to accelerate investment in clean energy innovation; and (iv) a 50/50 sharing between customers and the utilities of variances from the allowed ROE. In the fourth quarter of 2020, the BCUC approved: (i) the January 1, 2020 delivery rate increase; and (ii) an increase in 2021 delivery rates, effective January 1, 2021, reflecting the terms of this decision.

Generic Cost of Capital Proceeding: In January 2021, the BCUC issued a notice that a GCOC proceeding will be initiated in the second quarter of 2021 and will include a review of the common equity component of capital structure and the allowed ROE effective January 1, 2022.

FortisAlberta

2018 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 customer contribution policy ("ACCP") is accounted for between distribution facility owners, such as FortisAlberta, and transmission facility owners ("TFOs"). The decision prevented any future investment by FortisAlberta under the policy and directed that 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 November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

The AUC initiated a new proceeding in November 2020 to consider whether the ACCP should be modified on a prospective basis. A decision is expectein the second quarter of 2021.

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 22). 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 Credit Losses

Fortis and its subsidiaries recognize an allowance for credit losses (2019 - allowance for doubtful accounts) to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. 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) obligations 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 8) 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 for 2020 totalled $41 million (2019 - $40 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 23). 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 AESO toward funding the construction of transmission facilities.

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 2020 ranged from 0.9% to 39.8% (2019 - 0.9% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.5% for 2020 (2019 – 2.6%).

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

	2020		2019	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	32
Gas	**18-95**	**38**	15-95	36
Transmission				
Electric	**20-90**	**43**	20-90	43
Gas	**10-85**	**35**	5-85	32
Generation	**1-85**	**24**	1-85	25
Other	**2-70**	**14**	3-70	14

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 33.0% for 2020 (2019 – 1.0% to 33.0%).

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

	2020		2019	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**4**	3-10	4
Land, transmission and water rights	**43-90**	**56**	43-90	58
Other	**10-100**	**12**	10-100	12

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.

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 on each reporting unit, 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. When a quantitative assessment is necessary, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. 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.

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 8).

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 8).

Leases

A right-of-use asset and lease liability is recognized for all leases with a lease term greater than 12 months. 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.

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. Energy sales are 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 5). 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. DSUs, PSUs and RSUs issued pre-2020 represent cash-settled awards and RSUs issued in 2020 represent cash or share-settled awards, depending on settlement elections and share ownership requirements of the executive. 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, 2020 was $52.36 (2019 - $53.97). 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, 2020 was US$1.00=CA$1.27 (2019 – US$1.00=CA$1.30).

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=CA$1.34 for 2020 (2019 - US$1.00=CA$1.33).

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 recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8).

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
Fortis, ITC and UNS Energy use cash flow hedges, from time to time, 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 certain 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 of, 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 BECOL are not subject to income tax.

Differences between the income tax expense or recovery recognized under US GAAP and 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 8).

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 $3.4 billion as at December 31, 2020 (2019 - $2.8 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, rights-of-way 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 16) 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

Financial Instruments
Effective January 1, 2020, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimation of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The new guidance also requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. Adoption did not have a material impact on the consolidated financial statements and related disclosures.

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.

Future Accounting Pronouncements

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board. Any ASUs not included in these consolidated financial statements were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

4. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by its CEO in deciding how to allocate resources. Segment performance is evaluated principally 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 2020 or 2019.

Inter-company balances, transactions and profit between non-regulated and regulated entities, which are not eliminated on consolidation, are summarized below.

(in millions)	**2020**	2019
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**$ 25**	$ 23
Sale of capacity from the Waneta Expansion to FortisBC Electric[(1)]	**—**	17

(1) Reflects amounts to the April 16, 2019 disposition of the Waneta Expansion (Note 22)

As at December 31, 2020, accounts receivable included approximately $28 million due from Belize Electricity (2019 - $8 million).

Fortis periodically provides short-term financing to its subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2020, there were no material inter-segment loans outstanding (2019 - $279 million). The interest charged on inter-segment loans in 2020 and 2019 was not material.

	REGULATED								NON-REGULATED			
Year ended December 31, 2020 *(in millions)*	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	$ 1,744	$ 2,260	$ 953	$ 1,385	$ 596	$ 424	$ 1,485	**$ 8,847**	**$ 88**	**$ —**	**$ —**	**$ 8,935**
Energy supply costs	—	847	232	468	—	119	893	**2,559**	**3**	**—**	**—**	**2,562**
Operating expenses	438	627	503	341	148	117	194	**2,368**	**30**	**39**	**—**	**2,437**
Depreciation and amortization	295	330	90	237	212	61	183	**1,408**	**16**	**4**	**—**	**1,428**
Operating income	1,011	456	128	339	236	127	215	**2,512**	**39**	**(43)**	**—**	**2,508**
Other income, net	40	40	31	8	2	5	10	**136**	**5**	**13**	**—**	**154**
Finance charges	324	125	48	142	104	72	77	**892**	**—**	**150**	**—**	**1,042**
Income tax expense	179	69	20	29	1	4	21	**323**	**5**	**(97)**	**—**	**231**
Net earnings	548	302	91	176	133	56	127	**1,433**	**39**	**(83)**	**—**	**1,389**
Non-controlling interests	99	—	—	1	—	—	15	**115**	**—**	**—**	**—**	**115**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**65**	**—**	**65**
Net earnings attributable to common equity shareholders	$ 449	$ 302	$ 91	$ 175	$ 133	$ 56	$ 112	**$ 1,318**	**$ 39**	**$ (148)**	**$ —**	**$ 1,209**
Goodwill	$ 7,810	$ 1,758	$ 574	$ 913	$ 228	$ 235	$ 247	**$ 11,765**	**$ 27**	**$ —**	**$ —**	**$ 11,792**
Total assets	20,358	10,802	3,939	7,695	5,084	2,441	4,261	**54,580**	**745**	**209**	**(53)**	**55,481**
Capital expenditures	1,182	1,200	339	471	420	135	273	**4,020**	**19**	**—**	**—**	**4,039**
Year ended December 31, 2019 *(in millions)*												
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

5. REVENUE

(in millions)	**2020**	2019
Electric and gas revenue		
United States		
ITC	**$ 1,726**	$ 1,697
UNS Energy	**2,019**	1,966
Central Hudson	**941**	894
Canada		
FortisBC Energy	**1,336**	1,289
FortisAlberta	**580**	576
FortisBC Electric	**358**	362
Newfoundland Power	**707**	671
Maritime Electric	**215**	209
FortisOntario	**222**	206
Caribbean		
Caribbean Utilities	**238**	270
FortisTCI	**77**	85
Total electric and gas revenue	**8,419**	8,225
Other services revenue [(1)]	**325**	374
Revenue from contracts with customers	**8,744**	8,599
Alternative revenue [(2)]	**64**	116
Other revenue	**127**	68
Total revenue	**$ 8,935**	$ 8,783

[(1)] *Includes $227 million and $273 million from regulated operations for 2020 and 2019, respectively*
[(2)] *Includes a $40 million and $91 million base ROE adjustment associated with the May 2020 and November 2019 FERC decisions, respectively (Notes 2 and 8)*

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 including the flow through of commodity costs.

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; and (iii) 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 significant alternative revenue programs of Fortis' utilities 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 8). 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.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE in 2020 (2019 - variances from formula-driven operation and maintenance expenses and capital expenditures). This mechanism is in place until the expiry of the current multi-year rate plan for 2020 to 2024. Additionally, variances between forecast and actual customer-use rates and industrial and other customer revenue are captured in a revenue stabilization account and a flow-through deferral account to be refunded to, or received from, customers in rates within two years.

Other Revenue

Other revenue primarily includes gains or losses on energy contract derivatives and regulatory deferrals at FortisBC Energy and FortisBC Electric reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2020**	2019
Trade accounts receivable	**$ 595**	$ 504
Unbilled accounts receivable	**571**	601
Allowance for credit losses [(1)]	**(64)**	(35)
	1,102	1,070
Income tax receivable	**72**	35
Other [(2)]	**195**	192
	$ 1,369	$ 1,297

[(1)] *Allowance for doubtful accounts for 2019*
[(2)] *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 27)*

Allowance for Credit Losses

The allowance for credit losses balance changed during 2020 as follows.

(in millions)	**2020**
Balance, beginning of year	**$ (35)**
Credit loss expensed	**(36)**
Credit loss deferred (Note 2)	**(6)**
Write-offs, net of recoveries	**14**
Foreign exchange	**(1)**
Balance, end of year	**$ (64)**

The allowance for doubtful accounts balance changed during 2019 as follows.

(in millions)	2019
Balance, beginning of year	$ (33)
Bad debt expensed	(21)
Write-offs, net of recoveries	18
Foreign exchange	1
Balance, end of year	**$ (35)**

7. INVENTORIES

(in millions)	**2020**	2019
Materials and supplies	**$ 297**	$ 294
Gas and fuel in storage	**101**	69
Coal inventory	**24**	31
	$ 422	$ 394

8. REGULATORY ASSETS AND LIABILITIES

(in millions)	**2020**	2019
Regulatory assets		
Deferred income taxes (Notes 3 and 24)	**$ 1,697**	$ 1,556
Employee future benefits (Notes 3 and 25)	**588**	530
Deferred energy management costs [(1)]	**334**	279
Rate stabilization and related accounts [(2)]	**213**	208
Deferred lease costs [(3)]	**122**	116
Manufactured gas plant site remediation deferral (Note 16)	**107**	81
Derivatives (Notes 3 and 27)	**73**	119
Generation early retirement costs [(4)]	**55**	88
Other regulatory assets [(5)]	**399**	406
Total regulatory assets	**3,588**	3,383
Less: Current portion	**(470)**	(425)
Long-term regulatory assets	**$ 3,118**	$ 2,958
Regulatory liabilities		
Deferred income taxes (Notes 3 and 24)	**$ 1,361**	$ 1,440
Asset removal cost provision (Note 3)	**1,206**	1,187
Rate stabilization and related accounts [(2)]	**104**	166
Renewable energy surcharge [(6)]	**100**	94
Energy efficiency liability [(7)]	**83**	101
Employee future benefits (Notes 3 and 25)	**43**	45
Electric and gas moderator account [(8)]	**28**	45
ROE complaints liability (Note 2)	**16**	91
Other regulatory liabilities [(5)]	**162**	189
Total regulatory liabilities	**3,103**	3,358
Less: Current portion	**(441)**	(572)
Long-term regulatory liabilities	**$ 2,662**	$ 2,786

(1) *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 two to 10 years.

(2) *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 of 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 5).

(3) *Deferred Lease Costs:* Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 15). 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.

(4) *Generation Early Retirement Costs:* TEP and the co-owners of Navajo Generating Station ("Navajo") retired Navajo in 2019, with related decommissioning activities continuing through 2054. TEP also retired Sundt Generating Facility Units 1 and 2 ("Sundt") in 2019. The ACC approved the recovery of the retirement costs of Navajo and Sundt over a 10-year period as part of the 2020 Rate Order (Note 2).

(5) *Other Regulatory Assets and Liabilities:* Comprised of regulatory assets and liabilities individually less than $10 million.

(6) *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 ("RECs"). 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 9) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are utilized for RES compliance, energy supply costs and revenue are recognized in an equal amount.

(7) *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.

(8) *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 $1,678 million and $1,510 million as at December 31, 2020 and 2019, 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.

9. OTHER ASSETS

(in millions)	**2020**	2019
Supplemental Executive Retirement Plan ("SERP")	**$ 155**	$ 145
Renewable Energy Credits (Note 8)	**106**	99
Equity investment - Belize Electricity	**80**	71
Employee future benefits (Note 25)	**66**	63
Other investments	**66**	43
Operating leases (Note 15)	**40**	46
Deferred compensation plan	**36**	30
Equity Investment - Wataynikaneyap Partnership	**12**	12
Other [(1)]	**109**	111
	$ 670	$ 620

[(1)] *Includes the fair value of derivatives (Note 27)*

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). 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 27).

10. PROPERTY, PLANT AND EQUIPMENT

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2020			
Distribution			
Electric	**$ 11,921**	**$ (3,223)**	**$ 8,698**
Gas	**5,546**	**(1,422)**	**4,124**
Transmission			
Electric	**15,888**	**(3,413)**	**12,475**
Gas	**2,360**	**(719)**	**1,641**
Generation	**6,441**	**(2,550)**	**3,891**
Other	**4,178**	**(1,347)**	**2,831**
Assets under construction	**2,012**	**—**	**2,012**
Land	**326**	**—**	**326**
	$ 48,672	**$ (12,674)**	**$ 35,998**
2019			
Distribution			
Electric	$ 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

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 Aitken Creek.

As at December 31, 2020, assets under construction were primarily associated with ongoing transmission projects at ITC and the addition of wind-powered electric generating capacity at UNS Energy.

The cost of PPE under finance lease as at December 31, 2020 was $322 million (2019 - $514 million) and related accumulated depreciation was $111 million (2019 - $206 million) (Note 15).

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, 2020, interests in jointly owned facilities consisted of the following.

(in millions, except as noted)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	1.0-80.0	**$ 980**	**$ (381)**	**$ 599**
Springerville Common Facilities [(1)]	86.0	**505**	**(251)**	**254**
San Juan Unit 1 ("San Juan")	50.0	**370**	**(304)**	**66**
Springerville Coal Handling Facilities	83.0	**268**	**(121)**	**147**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**235**	**(97)**	**138**
Gila River Common Facilities	50.0	**108**	**(36)**	**72**
Luna Energy Facility ("Luna")	33.3	**74**	**(2)**	**72**
		$ 2,540	**$ (1,192)**	**$ 1,348**

[(1)] In December 2020 TEP purchased an additional 32.2% undivided interest in the Springerville Common Facilities, previously recorded as a finance lease (Note 15). Also in December 2020, TEP sold a 14% interest in the Springerville Common Facilities.

11. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2020			
Computer software	**$ 932**	**$ (524)**	**$ 408**
Land, transmission and water rights	**898**	**(142)**	**756**
Other	**114**	**(64)**	**50**
Assets under construction	**77**	**—**	**77**
	$ 2,021	**$ (730)**	**$ 1,291**
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

Included in the cost of land, transmission and water rights as at December 31, 2020 was $36 million (2019 - $133 million) not subject to amortization. Amortization expense was $131 million for 2020 (2019 - $125 million). Amortization is estimated to average approximately $81 million for each of the next five years.

12. GOODWILL

(in millions)	2020	2019
Balance, beginning of year	**$ 12,004**	$ 12,530
Foreign currency translation impacts [(1)]	**(212)**	(526)
Balance, end of year	**$ 11,792**	$ 12,004

[(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 2020 or 2019.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	2020	2019
Trade accounts payable	**$ 707**	$ 754
Employee compensation and benefits payable	**248**	229
Dividends payable	**241**	228
Accrued taxes other than income taxes	**224**	223
Interest payable	**215**	212
Customer and other deposits	**214**	226
Gas and fuel cost payable	**188**	225
Fair value of derivatives (Note 27)	**56**	83
Manufactured gas plant site remediation (Note 16)	**31**	31
Employee future benefits (Note 25)	**26**	24
Other	**171**	167
	$ 2,321	$ 2,402

14. LONG-TERM DEBT

(in millions)	Maturity Date	**2020**	2019
ITC			
Secured US First Mortgage Bonds -			
4.31% weighted average fixed rate (2019 - 4.46%)	2024-2055	**$ 2,755**	$ 2,624
Secured US Senior Notes -			
4.00% weighted average fixed rate (2019 - 4.26%)	2040-2055	**923**	747
Unsecured US Senior Notes -			
3.61% weighted average fixed rate (2019 - 3.79%)	2022-2043	**4,136**	3,312
Unsecured US Shareholder Note -			
6.00% fixed rate (2019 - 6.00%)	2028	**253**	258
Unsecured US Term Loan Credit Agreement -			
2.35% weighted average fixed rate	n/a	**—**	260
UNS Energy			
Unsecured US Tax-Exempt Bonds - 4.34% weighted			
average fixed and variable rate (2019 - 4.64%)	2029-2030	**362**	603
Unsecured US Fixed Rate Notes -			
3.86% weighted average fixed rate (2019 - 4.38%)	2021-2050	**2,704**	1,851
Central Hudson			
Unsecured US Promissory Notes - 3.94% weighted			
average fixed and variable rate (2019 - 4.27%)	2021-2060	**1,078**	986
FortisBC Energy			
Unsecured Debentures -			
4.72% weighted average fixed rate (2019 - 4.87%)	2026-2050	**2,995**	2,795
FortisAlberta			
Unsecured Debentures -			
4.49% weighted average fixed rate (2019 - 4.64%)	2024-2052	**2,360**	2,185
FortisBC Electric			
Secured Debentures -			
8.80% fixed rate (2019 - 8.80%)	2023	**25**	25
Unsecured Debentures -			
4.87% weighted average fixed rate (2019 - 5.05%)	2021-2050	**785**	710
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
5.61% weighted average fixed rate (2019 - 6.14%)	2022-2060	**634**	571
Secured First Mortgage Bonds -			
5.66% weighted average fixed rate (2019 - 5.66%)	2025-2061	**220**	220
Unsecured Senior Notes -			
4.45% weighted average fixed rate (2019 - 4.45%)	2041-2048	**152**	152
Unsecured US Senior Loan Notes and Bonds - 4.41% weighted			
average fixed and variable rate (2019 - 4.53%)	2022-2049	**648**	645
Corporate and Other			
Unsecured US Senior Notes and Promissory Notes -			
3.81% weighted average fixed rate (2019 - 3.80%)	2021-2044	**2,685**	2,903
Unsecured Debentures -			
6.50% fixed rate (2019 - 6.50%)	2039	**200**	200
Unsecured Senior Notes - 2.85% fixed rate (2019 - 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**980**	640
Fair value adjustment - ITC acquisition		**119**	133
Total long-term debt (Note 27)		**24,514**	22,320
Less: Deferred financing costs and debt discounts		**(147)**	(129)
Less: Current installments of long-term debt		**(1,254)**	(690)
		$ 23,113	$ 21,501

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 agreements have covenants that 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 as noted)	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount** *($)*	**Use of Proceeds**
ITC						
Unsecured term loan credit agreement	January	*(1)*	2021	**US**	**75**	*(2)(3)*
Unsecured term loan credit agreement *(4)*	January	*(5)*	2021	**US**	**200**	*(4)*
Unsecured senior notes	May	2.95	2030	**US**	**700**	*(2)(3)(6)*
First mortgage bonds	July	3.13	2051	**US**	**180**	*(2)(3)(7)*
Secured senior notes	October	3.02	2055	**US**	**150**	*(2)(3)(7)(8)*
UNS Energy						
Unsecured senior notes	April	4.00	2050	**US**	**350**	*(2)(3)*
Unsecured senior notes	August	1.50	2030	**US**	**300**	*(7)*
Unsecured senior notes	September	2.17	2032	**US**	**50**	*(2)(3)*
Central Hudson						
Unsecured senior notes	May	3.42	2050	**US**	**30**	*(3)*
Unsecured senior notes	July	3.62	2060	**US**	**30**	*(3)(7)*
Unsecured senior notes	September	2.03	2030	**US**	**40**	*(8)*
Unsecured senior notes	November	2.03	2030	**US**	**30**	*(3)(7)*
FortisBC Energy						
Unsecured debentures	July	2.54	2050		**200**	*(7)*
FortisAlberta						
Unsecured senior debentures	December	2.63	2051		**175**	*(2)*
FortisBC Electric						
Unsecured debentures	May	3.12	2050		**75**	*(2)*
Newfoundland Power						
First mortgage sinking fund bonds	April	3.61	2060		**100**	*(2)(3)*
FortisTCI						
Unsecured senior notes	June/October	5.30	2035	**US**	**30**	*(7)(8)*
Unsecured senior notes	October/December	3.25	2030	**US**	**10**	*(3)*

(1) Floating rate of a one-month LIBOR plus a spread of 0.45%
(2) Repay credit facility borrowings
(3) General corporate purposes
(4) Maximum amount of borrowings under this agreement of US$400 million has been drawn; current period borrowings were used to repay an outstanding commercial paper balance.
(5) Floating rate of a two-month LIBOR plus a spread of 0.60%
(6) Early redemption of unsecured term loan borrowing of US$400 million
(7) Finance capital expenditures
(8) Repay maturing long-term debt

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.

(in millions)		**Total**
2021	$	1,254
2022		823
2023		1,786
2024		1,088
2025		484
Thereafter		19,079
	$	24,514

In December 2020 Fortis filed a short-form base shelf prospectus with a25-month life under which it may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $2.0 billion. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Credit Facilities

(in millions)	Regulated Utilities	Corporate and Other	**2020**	2019
Total credit facilities	$ 3,700	$ 1,881	**$ 5,581**	$ 5,590
Credit facilities utilized:				
Short-term borrowings [1]	(132)	—	**(132)**	(512)
Long-term debt (including current portion) [2]	(714)	(266)	**(980)**	(640)
Letters of credit outstanding	(77)	(53)	**(130)**	(114)
Credit facilities unutilized	$ 2,777	$ 1,562	**$ 4,339**	$ 4,324

[1] *The weighted average interest rate was approximately 0.8% (2019 - 3.2%).*
[2] *The weighted average interest rate was approximately 0.9% (2019 - 2.4%). The current portion was $651 million (2019 - $252 million).*

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than approximately25% of the total facilities. Approximately $5.3 billion of the total credit facilities are committed facilities with maturities ranging from 2021 through 2025.

Consolidated credit facilities of approximately $5.6 billion as at December 31, 2020 are itemized below.

(in millions)		Amount *($)*	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [1]	**US**	**900**	October 2023
UNS Energy	**US**	**500**	October 2022
Central Hudson	**US**	**200**	March 2025
FortisBC Energy		**700**	August 2024
FortisAlberta		**250**	August 2024
FortisBC Electric		**150**	April 2024
Other Electric		**190**	[2]
Other Electric	**US**	**70**	January 2025
Corporate and Other		**1,850**	[3]
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**30**	n/a
FortisBC Energy - uncommitted credit facility		**55**	March 2022
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**	June 2021
Corporate and Other - unsecured non-revolving facility		**30**	n/a

[1] *ITC also has a US$400 million commercial paper program, under which US$67 million was outstanding as at December 31, 2020, as reported in short-term borrowings.*
[2] *$40 million in June 2021, $50 million in February 2022 and $100 million in August 2024*
[3] *$500 million in April 2021, $50 million in April 2022 and $1.3 billion in July 2024*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 21 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 leased premises.

The Corporation's subsidiaries also have finance leases related to generating facilities with remaining terms of up to 35 years.

Leases were presented on the consolidated balance sheets as follows.

(in millions)	**2020**	2019
Operating leases		
Other assets	**$ 40**	$ 46
Accounts payable and other current liabilities	**(7)**	(8)
Other liabilities	**(33)**	(38)
Finance leases [(1) (2)]		
Regulatory assets	**$ 122**	$ 116
PPE, net	**211**	308
Accounts payable and other current liabilities	**(2)**	(24)
Finance leases	**(331)**	(413)

[(1)] *FortisBC Electric has a finance lease for the BPPA (Note 8), 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)] *In December 2020 TEP purchased a 32.2% undivided interest in the Springerville Common Facilities, which had previously been leased (Note 10).*

The components of lease expense were as follows.

(in millions)	**2020**	2019
Operating lease cost	**$ 10**	$ 10
Finance lease cost:		
Amortization	**14**	17
Interest	**34**	48
Variable lease cost	**20**	39
Total lease cost	**$ 78**	$ 114

As at December 31, 2020, the present value of minimum lease payments was as follows.

(in millions)	Operating Leases	Finance Leases	**Total**
2021	$ 8	$ 33	**$ 41**
2022	7	34	**41**
2023	6	34	**40**
2024	4	34	**38**
2025	3	34	**37**
Thereafter	22	1,056	**1,078**
	50	1,225	**1,275**
Less: Imputed interest	(10)	(892)	**(902)**
Total lease obligations	40	333	**373**
Less: Current installments	(7)	(2)	**(9)**
	$ 33	$ 331	**$ 364**

Supplemental lease information was as follows.

(in millions, except as noted)	**2020**	2019
Weighted average remaining lease term *(years)*		
Operating leases	**10**	10
Finance leases	**35**	27
Weighted average discount rate *(%)*		
Operating leases	**4.0**	4.1
Finance leases	**5.1**	4.8
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**$ (10)**	$ (10)
Operating cash flows used for finance leases	**(2)**	(47)
Financing cash flows used for finance leases	**(25)**	(16)
Investing cash flows used for finance leases	**(87)**	(212)

See Note 26 for non-cash transactions that resulted in right-of-use assets obtained in exchange for new lease liabilities.

16. OTHER LIABILITIES

(in millions)	**2020**	2019
Employee future benefits (Note 25)	**$ 905**	$ 832
Customer and other deposits	**132**	70
AROs (Note 3)	**130**	148
Stock-based compensation plans (Note 21)	**86**	83
Manufactured gas plant site remediation [(1)]	**69**	48
Fair value of derivatives (Note 27)	**50**	68
Mine reclamation obligations [(2)]	**47**	43
Retail energy contract [(3)]	**46**	—
Deferred compensation plan (Note 9)	**43**	33
Operating leases	**33**	38
Other	**58**	83
	$ 1,599	$ 1,446

(1) Environmental regulations require Central Hudson to investigate sites at which it 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, 2020, an obligation of $96 million was recognized, including a current portion of $27 million recognized in accounts payable and other current liabilities (Note 13). 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 8).

(2) 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 $61 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.

(3) FortisAlberta entered into an eight-year agreement with an existing retail energy provider to continue to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment in 2020 which will be amortized to earnings over the life of the agreement.

17. 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.

18. EARNINGS PER COMMON SHARE

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

	2020			2019		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**$ 1,209**	**464.8**	**$ 2.60**	$ 1,655	436.8	$ 3.79
Potential dilutive effect of stock options	**—**	**0.6**	**—**	—	0.7	—
Diluted EPS	**$ 1,209**	**465.4**	**$ 2.60**	$ 1,655	437.5	$ 3.78

19. PREFERENCE SHARES

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

Issued and Outstanding	**2020**		2019	
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	**7,665**	**188**	7,025	172
Series I	**2,335**	**57**	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 ($)	Reset Dividend Yield (%)	Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a One-For-One Basis
Perpetual fixed rate						
Series F	4.90	1.2250	—	Currently Redeemable	25.00	—
Series J [3]	4.75	1.1875	—	Currently Redeemable	25.25	—
Fixed rate reset [4] [5]						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H [6]	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating rate reset [5] [7]						
Series I	2.10	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	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 are redeemable as of December 1, 2021 and thereafter at $25.00 per share.*

[4] *On the redemption and/or conversion option date, and on 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 H was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*

[7] *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 June 1, 2020, 267,341 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I, and 907,577 First Preference Shares, Series I were converted on a one-for-one basis into First Preference Shares, Series H.

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.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	Opening Balance	Net Change	Ending Balance
2020			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**$ 713**	**$ (336)**	**$ 377**
Hedges of net investments in foreign operations	**(359)**	**60**	**(299)**
Income tax expense	**(3)**	**(3)**	**(6)**
	351	**(279)**	**72**
Other			
Cash flow hedges (Note 27)	**17**	**(21)**	**(4)**
Unrealized employee future benefits losses (Note 25)	**(38)**	**(11)**	**(49)**
Income tax recovery	**6**	**9**	**15**
	(15)	**(23)**	**(38)**
Accumulated other comprehensive income	**$ 336**	**$ (302)**	**$ 34**
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 27)	11	6	17
Unrealized employee future benefits losses (Note 25)	(20)	(18)	(38)
Income tax recovery	1	5	6
	(8)	(7)	(15)
Accumulated other comprehensive income	$ 928	$ (592)	$ 336

21. 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 thanthree years after the 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 2020 and 2019.

	2020	2019
Options granted *(in thousands)*	**686**	852
Exercise price *($)* [1]	**58.40**	47.57
Grant date fair value *($)*	**4.20**	3.70
Valuation assumptions:		
Dividend yield *(%)* [2]	**3.7**	3.8
Expected volatility *(%)* [3]	**15.8**	15.2
Risk-free interest rate *(%)* [4]	**1.2**	1.8
Weighted average expected life *(years)* [5]	**5.2**	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 2020.

	Total Options		Non-vested Options [1]	
(in thousands, except as noted)	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, beginning of year	**3,418**	**$ 41.18**	**1,910**	**$ 3.43**
Granted	**686**	**$ 58.40**	**686**	**$ 4.20**
Exercised	**(825)**	**$ 39.21**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(807)**	**$ 3.25**
Cancelled/Forfeited	**(17)**	**$ 50.02**	**(17)**	**$ 3.79**
Options outstanding, end of year	**3,262**	**$ 45.26**	**1,772**	**$ 3.81**
Options vested, end of year [2]	**1,490**	**$ 39.40**		

(1) *As at December 31, 2020, 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, 2020, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $19 million.*

The following table summarizes additional stock option information.

(in millions)	2020	2019
Stock options exercised:		
Cash received for exercise price	**$ 32**	$ 51
Intrinsic value realized by employees	**15**	22

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.

	2020	2019
Number of units *(in thousands)*		
Beginning of year	**165**	177
Granted	**25**	29
Notional dividends reinvested	**6**	6
Paid out	**(49)**	(47)
End of year	**147**	165

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in long-term other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2020 or 2019.

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, 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 vesting 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.

	2020	2019
Number of units *(in thousands)*		
Beginning of year	**2,118**	1,763
Granted	**586**	690
Notional dividends reinvested	**71**	73
Paid out	**(735)**	(357)
Cancelled/forfeited	**(64)**	(51)
End of year	**1,976**	2,118
Additional information *(in millions)*		
Compensation expense recognized	**$ 58**	$ 74
Compensation expense unrecognized [(1)]	**32**	35
Cash payout	**54**	16
Accrued liability as at December 31 [(2)]	**108**	106
Aggregate intrinsic value as at December 31 [(3)]	**140**	141

(1) Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years
(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)
(3) 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 or, beginning with the 2020 grant, common shares of the Corporation. RSUs issued in 2020 may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executives' settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

	2020	2019
Number of units *(in thousands)*		
Beginning of year	**1,050**	717
Granted	**356**	429
Notional dividends reinvested	**37**	35
Paid out	**(355)**	(92)
Cancelled/forfeited	**(40)**	(39)
End of year	**1,048**	1,050
Additional information *(in millions)*		
Compensation expense recognized	**$ 20**	$ 24
Compensation expense unrecognized [(1)]	**15**	17
Cash payout	**19**	4
Accrued liability as at December 31 [(2)]	**39**	39
Aggregate intrinsic value as at December 31 [(3)]	**54**	56

(1) Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years
(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)
(3) Relates to outstanding RSUs and reflects a weighted average contractual life of one year

22. 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, and the related non-controlling interest was removed from equity.

Up to the date of disposition, excluding the gain as noted above, the Waneta Expansion contributed $17 million to earnings before income tax expense, of which Fortis' share was 51%.

23. OTHER INCOME, NET

(in millions)	2020	2019
Equity component of AFUDC	**$ 78**	$ 74
Equity income	**20**	(1)
Derivative gains	**13**	17
Interest income	**13**	16
Gain on repayment of debt	**—**	11
Other	**30**	21
	$ 154	$ 138

24. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

(in millions)	**2020**	2019
Gross deferred income tax assets		
Regulatory liabilities	**$ 527**	$ 588
Tax loss and credit carryforwards	**494**	532
Employee future benefits	**175**	165
Unrealized foreign exchange losses on long-term debt[(1)]	**33**	40
Other	**83**	88
	1,312	1,413
Valuation allowance [(1)]	**(22)**	(22)
Net deferred income tax asset	**$ 1,290**	$ 1,391
Gross deferred income tax liabilities		
PPE	**$ (4,253)**	$ (3,986)
Regulatory assets	**(263)**	(269)
Intangible assets	**(118)**	(105)
	(4,634)	(4,360)
Net deferred income tax liability	**$ (3,344)**	$ (2,969)

(1) *These deferred income tax assets can be utilized only to the extent that the Corporation has capital gains to offset the underlying capital losses. Management believes that it is more likely than not that a $22 million shortfall exists in this regard and, therefore, the Corporation has recognized a $22 million valuation allowance. Management believes that, based on its historical pattern of taxable income, Fortis will generate the necessary income in the future to realize all other deferred income tax assets.*

Unrecognized Tax Benefits

(in millions)	**2020**	2019
Beginning of year	**$ 36**	$ 38
Additions related to current year	**3**	5
Adjustments related to prior years	**(6)**	(7)
End of year	**$ 33**	$ 36

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2020. Fortis hasnot recognized interest expense in 2020 and 2019 related to unrecognized tax benefits.

Income Tax Expense

(in millions)	**2020**	2019
Canadian		
Earnings before income tax expense	**$ 333**	$ 901
Current income tax	**20**	49
Deferred income tax	**(16)**	42
Total Canadian	**$ 4**	$ 91
Foreign		
Earnings before income tax expense	**$ 1,287**	$ 1,240
Current income tax	**(15)**	(7)
Deferred income tax	**242**	205
Total Foreign	**$ 227**	$ 198
Income tax expense	**$ 231**	$ 289

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 as noted)	**2020**	2019
Earnings before income tax expense	**$ 1,620**	$ 2,141
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	28.5
Expected federal and provincial taxes at statutory rate	**$ 486**	$ 610
Decrease resulting from:		
Foreign and other statutory rate differentials	**(145)**	(124)
Difference between gain on sale for accounting and amounts calculated for tax purposes	**—**	(73)
Release of valuation allowance	**—**	(33)
AFUDC	**(20)**	(16)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(56)**	(48)
Items capitalized for accounting purposes but expensed for income tax purposes	**(26)**	(17)
Other	**(8)**	(10)
Income tax expense	**$ 231**	$ 289
Effective tax rate *(%)*	**14.3**	13.5

Income Tax Carryforwards

(in millions)	Expiring Year		**2020**
Canadian			
Capital loss	n/a	**$**	**27**
Non-capital loss	2035-2040		**200**
Other tax credits	2026-2040		**2**
			229
Unrecognized			**(26)**
			203
Foreign			
Federal and state net operating loss	2021-2040		**2,971**
Other tax credits	2022-2040		**34**
			3,005
Total income tax carryforwards recognized		**$**	**3,208**

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 2020 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2020 taxation years are still open for audit in United States jurisdictions.

25. 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, 2017 for the Corporation; December 31, 2018 for FortisBC Energy and FortisBC Electric (plan covering unionized employees); December 31, 2019 for the remaining FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; and December 31, 2020 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

(weighted average %)	**2020 Target Allocation**	**2020**	2019
Equities	**46**	**48**	47
Fixed income	**47**	**45**	46
Real estate	**6**	**6**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

(in millions)	**Level 1 [1]**	**Level 2 [1]**	**Level 3 [1]**	**Total**
2020				
Equities	**$ 713**	**$ 1,163**	**$ —**	**$ 1,876**
Fixed income	**197**	**1,580**	**—**	**1,777**
Real estate	**—**	**17**	**204**	**221**
Private equities	**—**	**—**	**20**	**20**
Cash and other	**8**	**17**	**—**	**25**
	$ 918	**$ 2,777**	**$ 224**	**$ 3,919**
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

[1] *See Note 27 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)	**2020**	2019
Balance, beginning of year	**$ 229**	$ 215
(Loss) return on plan assets	**(2)**	19
Foreign currency translation	**(1)**	(2)
Purchases, sales and settlements	**(2)**	(3)
Balance, end of year	**$ 224**	$ 229

Funded Status	**Defined Benefit Pension Plans**		**OPEB Plans**	
(in millions)	**2020**	2019	**2020**	2019
Change in benefit obligation [1]				
Balance, beginning of year	**$ 3,632**	$ 3,207	**$ 712**	$ 655
Service costs	**98**	77	**32**	27
Employee contributions	**17**	16	**2**	2
Interest costs	**113**	124	**22**	25
Benefits paid	**(162)**	(144)	**(27)**	(27)
Actuarial losses	**350**	439	**62**	46
Past service (credits) costs/plan amendments	**—**	1	**(3)**	4
Foreign currency translation	**(53)**	(88)	**(11)**	(20)
Balance, end of year [2] [3]	**$ 3,995**	$ 3,632	**$ 789**	$ 712
Change in value of plan assets				
Balance, beginning of year	**$ 3,208**	$ 2,830	**$ 343**	$ 293
Actual return on plan assets	**444**	523	**55**	62
Benefits paid	**(155)**	(138)	**(27)**	(27)
Employee contributions	**17**	18	**2**	2
Employer contributions	**62**	53	**28**	28
Foreign currency translation	**(48)**	(78)	**(10)**	(15)
Balance, end of year [4]	**$ 3,528**	$ 3,208	**$ 391**	$ 343
Funded status	**$ (467)**	$ (424)	**$ (398)**	$ (369)
Balance sheet presentation				
Long-term assets (Note 9)	**$ 58**	$ 46	**$ 8**	$ 17
Current liabilities (Note 13)	**(13)**	(12)	**(13)**	(12)
Long-term liabilities (Note 16)	**(512)**	(458)	**(393)**	(374)
	$ (467)	$ (424)	**$ (398)**	$ (369)

[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 $3,679 million as at December 31, 2020 (2019 - $3,352 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 market returns.*

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2020, the obligation was $3,290 million compared to plan assets of $2,777 million (2019 - $2,971 million and $2,511 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, 2020, the obligation was $3,037 million compared to plan assets of $2,741 million (2019 - $2,752 million and $2,478 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2020, the obligation was $589 million compared to plan assets of $183 million (2019 - $537 million and $151 million, respectively).

Net Benefit Cost [1]	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2020**	2019	**2020**	2019
Service costs	**$ 98**	$ 77	**$ 32**	$ 27
Interest costs	**113**	124	**22**	25
Expected return on plan assets	**(176)**	(161)	**(19)**	(16)
Amortization of actuarial losses (gains)	**33**	24	**(5)**	(4)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(2)**	(7)
Regulatory adjustments	**—**	2	**4**	3
	$ 67	$ 65	**$ 32**	$ 28

[1] *The non-service cost components of net periodic benefit cost are included in other income, net in 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)	**2020**	2019	**2020**	2019
Unamortized net actuarial losses (gains)	**$ 42**	$ 32	**$ (1)**	$ (2)
Unamortized past service costs	**1**	1	**7**	7
Income tax recovery	**(10)**	(8)	**(1)**	(1)
Accumulated other comprehensive income	**$ 33**	$ 25	**$ 5**	$ 4
Net actuarial losses (gains)	**$ 517**	$ 486	**$ 12**	$ (18)
Past service credits	**(7)**	(9)	**(8)**	(8)
Other regulatory deferrals	**13**	15	**18**	19
	$ 523	$ 492	**$ 22**	$ (7)
Regulatory assets (Note 8)	**$ 523**	$ 492	**$ 65**	$ 38
Regulatory liabilities (Note 8)	**—**	—	**(43)**	(45)
Net regulatory assets (liabilities)	**$ 523**	$ 492	**$ 22**	$ (7)

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory assets.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2020**	2019	**2020**	2019
Current year net actuarial losses	**$ 9**	$ 11	**$ 1**	$ —
Past service costs/plan amendments	**—**	—	**—**	5
Amortization of actuarial losses	**1**	1	**—**	—
Foreign currency translation	**—**	1	**—**	—
Income tax recovery	**(2)**	(5)	**—**	—
Total recognized in comprehensive income	**$ 8**	$ 8	**$ 1**	$ 5
Current year net actuarial losses	**$ 69**	$ 64	**$ 25**	$ 3
Past service costs (credits)/plan amendments	**—**	—	**(3)**	—
Amortization of actuarial (losses) gains	**(31)**	(23)	**5**	4
Amortization of past service (costs) credits	**2**	(1)	**3**	8
Foreign currency translation	**(7)**	(10)	**—**	—
Regulatory adjustments	**(2)**	—	**(1)**	(8)
Total recognized in regulatory assets	**$ 31**	$ 30	**$ 29**	$ 7

Significant Assumptions	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2020**	2019	**2020**	2019
Discount rate during the year [(1)]	**3.16**	4.05	**3.22**	4.10
Discount rate as at December 31	**2.63**	3.20	**2.64**	3.25
Expected long-term rate of return on plan assets [(2)]	**5.52**	5.78	**5.28**	5.50
Rate of compensation increase	**3.34**	3.33	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.61**	4.62

(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 2021 weighted average health care cost trend rate is 5.91% and is assumed to decrease over the next 11 years to the weighted average ultimate health care cost trend rate of 4.61% in 2031 and thereafter.*

Expected Benefit Payments	**Defined Benefit**	**OPEB**
(in millions)	**Pension Payments**	**Payments**
2021	$ 163	$ 27
2022	165	28
2023	170	30
2024	174	31
2025	180	32
2026-2030	984	174

During 2021 the Corporation expects to contribute $49 million for defined benefit pension plans and $33 million for OPEB plans.

In 2020 the Corporation expensed $42 million (2019 - $39 million) related to defined contribution pension plans.

26. SUPPLEMENTARY CASH FLOW INFORMATION

(in millions)	2020	2019
Cash paid (received) for		
Interest	**$ 1,027**	$ 1,007
Income taxes	**(26)**	(37)
Change in working capital		
Accounts receivable and other current assets	**$ (84)**	$ 1
Prepaid expenses	**(15)**	(8)
Inventories	**(36)**	(13)
Regulatory assets - current portion	**(49)**	(75)
Accounts payable and other current liabilities	**(100)**	(8)
Regulatory liabilities - current portion	**(150)**	(65)
	$ (434)	$ (168)
Non-cash investing and financing activities		
Accrued capital expenditures	**$ 400**	$ 382
Common share dividends reinvested	**114**	299
Contributions in aid of construction	**13**	15
Right-of-use assets obtained in exchange for operating lease liabilities	**3**	55
Exercise of stock options into common shares	**3**	5
Finance leases	**2**	88

27. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are 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 flow.

Cash flow associated with the settlement of all derivatives is 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 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 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, 2020, unrealized losses of $73 million (2019 - $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 - $2 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 which10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

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 or losses associated with changes in the fair value of these energy contracts are recognized in revenue and were not material for 2020 and 2019.

Total Return Swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $113 million and terms of one to three years expiring at varying dates through January 2023. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net and were not material for 2020 and 2019.

Foreign Exchange Contracts
The Corporation holds US dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through February 2022 and have a combined notional amount of $245 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net and were not material for 2020 and 2019.

Interest Rate Swaps
ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of $611 million, were terminated in May 2020 with the issuance of US$700 million senior notes. Realized losses of $31 million were recognized in other comprehensive income and are being reclassified to earnings as a component of interest expense over five years.

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 are recognized in other income, net and were not material for 2020 and 2019.

Recurring Fair Value Measures

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

(in millions)	**Level 1** [1]	**Level 2** [1]	**Level 3** [1]	**Total**
As at December 31, 2020				
Assets				
Energy contracts subject to regulatory deferral [2] [3]	**$ — $**	**38 $**	**— $**	**38**
Energy contracts not subject to regulatory deferral [2]	**—**	**6**	**—**	**6**
Foreign exchange contracts and total return swaps [2]	**16**	**—**	**—**	**16**
Other investments [4]	**126**	**—**	**—**	**126**
	$ 142 $	**44 $**	**— $**	**186**
Liabilities				
Energy contracts subject to regulatory deferral [3] [5]	**$ — $**	**(94) $**	**— $**	**(94)**
Energy contracts not subject to regulatory deferral [5]	**—**	**(12)**	**—**	**(12)**
	$ — $	**(106) $**	**— $**	**(106)**
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)

[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 fair value measurement.*

[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, with the exception of long-term wholesale trading contracts and certain gas swap contracts.*

[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 apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

(in millions)	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
As at December 31, 2020				
Derivative assets	**$ 44**	**$ 26**	**$ 10**	**$ 8**
Derivative liabilities	**(106)**	**(26)**	**(9)**	**(71)**
As at December 31, 2019				
Derivative assets	$ 30	$ 22	$ 10	$ (2)
Derivative liabilities	(151)	(22)	(2)	(127)

Volume of Derivative Activity

As at December 31, 2020, 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.

	2020	2019
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**522**	628
Electricity power purchase contracts *(GWh)*	**2,781**	3,198
Gas swap contracts *(PJ)*	**156**	168
Gas supply contract premiums *(PJ)*	**203**	241
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,588**	1,855
Gas swap contracts *(PJ)*	**36**	43

[(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. As a result of the impact of the COVID-19 pandemic, certain of the Corporation's utilities have temporarily suspended non-payment disconnects, delayed customer rate increases and deferred the recovery of costs (Note 2). The Corporation has seen an increase in accounts receivable and, accordingly, its allowance for credit losses during 2020 (Note 6).

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 MISO 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, 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 in the event of 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 $88 million as at December 31, 2020 (2019 - $161 million).

Hedge of Foreign Net Investments

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 flow 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, 2020, US$2.3 billion (2019 - US$2.2 billion) of corporately issued US dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.2 billion (2019 - US$9.7 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, 2020, the carrying value of long-term debt, including current portion, was $24.5 billion (2019 - $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 - $25.3 billion).

28. COMMITMENTS AND CONTINGENCIES

As at December 31, 2020, unconditional minimum purchase obligations were as follows.

(in millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Waneta Expansion capacity agreement [(1)]	**$ 2,576**	$ 52	$ 53	$ 54	$ 55	$ 56	$ 2,306
Gas and fuel purchase obligations [(2)]	**2,355**	679	453	312	192	124	595
Power purchase obligations [(3)]	**1,867**	249	208	188	191	180	851
Renewable PPAs [(4)]	**1,380**	102	102	101	101	101	873
ITC easement agreement [(5)]	**381**	13	13	13	13	13	316
Debt collection agreement [(6)]	**112**	3	3	3	3	3	97
Renewable energy credit purchase agreements [(7)]	**97**	15	14	16	9	7	36
Other [(8)]	**116**	48	5	4	4	3	52
	$ 8,884	$ 1,161	$ 851	$ 691	$ 568	$ 487	$ 5,126

[(1)] FortisBC Electric is a party to an agreement to purchase capacity from the Waneta Expansion for forty-years, beginning April 2015.

[(2)] *FortisBC Energy ($1,482 million):* includes contracts for the purchase of gas, gas transportation and storage services, expiring in 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, 2020.

UNS Energy ($747 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 through 2040.

(3) *Maritime Electric ($910 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 December 2026.

FortisOntario ($599 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 through December 2030.

FortisBC Electric ($295 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 2027 through 2043, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. Amounts are the estimated future payments.

(5) 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 unless METC gives notice of non-renewal at least one year in advance.

(6) 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.

(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) Includes a $24 million payment to be made in 2021 under the Oso Grande Wind Project build-transfer agreement by UNS Energy, as well as AROs 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. In the event a lender under the 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.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2020, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $94 million, for which it has issued a parental guarantee. As at December 31, 2020, there was no obligation under this guarantee.

As at December 31, 2020, FortisBC Holdings Inc. ("FHI") had $69 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.

Management Discussion and Analysis

For the year ended December 31, 2020
Dated February 11, 2021

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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 2020 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 46. 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.

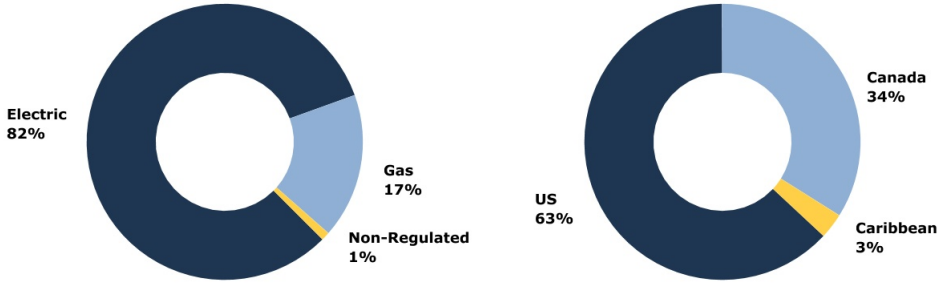
Financial information herein has been prepared in accordance with US GAAP (except for indicated Non-US GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following US dollar-to-Canadian dollar exchange rates: (i) average of 1.34 and 1.33 for the years ended December 31, 2020 and 2019, respectively; (ii) 1.27 and 1.30 as at December 31, 2020 and 2019, respectively; (iii) average of 1.30 and 1.32 for the quarters ended December 31, 2020 and 2019, respectively; and (iv) 1.32 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 48.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $8.9 billion and total assets of $55 billion as at December 31, 2020.

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, 2020, 66% of the Corporation's assets were located outside Canada and 59% of 2020 revenue was derived from foreign operations.

Total Assets at December 31, 2020



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. Earnings, 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 consists 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.

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 its capital plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2020 Annual Financial Statements.

SIGNIFICANT ITEMS

COVID-19 Pandemic

The Corporation's utilities continue to reliably and safely deliver an essential service during the COVID-19 Pandemic. Developments are continuously monitored with commensurate measures being taken. The Corporation's utilities have assessed supply chain risk and other potential impacts of the pandemic to ensure that they can continue to provide safe, reliable service while supporting public health.

Excluding the impact of the delay in TEP's general rate application (see "Regulatory Highlights" on page 15), the COVID-19 Pandemic did not have a material impact on the Corporation's capital expenditures, revenue or earnings in 2020. The financial impact to Fortis approximated $0.05 per common share and reflected: (i) reduced sales in the Caribbean; and (ii) higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

Further information regarding the key impact areas for Fortis with respect to the pandemic is summarized below.

Revenue

Energy sales across all of the Corporation's utilities have been impacted by the closure and reopening of non-essential businesses along with stay-at-home orders and other economic impacts related to the COVID-19 Pandemic. Generally, work-from-home practices have resulted in an increase in residential sales while commercial and industrial sales have decreased.

Regulatory mechanisms function to protect approximately 62% of the Corporation's annual revenue from changes in sales. Of the remaining 38%, principally at UNS Energy and the Other Electric segment, approximately 21% is residential and 17% is commercial and industrial. Overall, approximately 83% of revenues are either protected by regulatory mechanisms or derived from residential sales.

Since the start of the COVID-19 Pandemic in 2020, as compared to the same period in 2019, residential electricity sales at UNS Energy increased by 17%, due mainly to warmer temperatures and work-from-home practices. Commercial and industrial electricity sales decreased by 2%, resulting in an overall sales increase of 7%. Excluding weather, retail electricity sales increased 2%.

Sales at the Other Electric segment decreased by 2% since the start of the COVID-19 Pandemic, as compared to the same period in 2019. This was comprised of a 3% increase in residential sales and an 8% decrease in commercial sales, due largely to reduced tourism-related activities in the Caribbean.

Overall, variations in 2020 sales associated with the COVID-19 Pandemic at UNS Energy and the Other Electric segment did not have a material impact on Fortis. While the Corporation does not expect the COVID-19 Pandemic to materially impact Fortis in 2021, the residential and commercial sales mix, particularly for UNS Energy and the Other Electric segment, will continue to be evaluated. Overall, the estimated annual impact on EPS of a 1% change in sales at each of UNS Energy and the Other Electric segment is approximately $0.01.

Capital Expenditures

Capital expenditures were not materially impacted by the COVID-19 Pandemic. Total expenditures of $4.2 billion were broadly consistent with the 2020 capital plan. The Corporation does not expect the COVID-19 Pandemic to impact its overall five-year capital plan, although certain planned expenditures may shift within the five-years depending on the length and severity of the pandemic.

Liquidity

Fortis is well positioned with strong liquidity due, in part, to a $1.2 billion common equity offering and the sale of the Waneta Expansion in 2019. As at December 31, 2020, total consolidated credit facilities were $5.6 billion with $4.3 billion unutilized.

Fortis and its utilities continue to be successful in accessing capital markets. See "Liquidity and Capital Resources" on page 19.

The economic impact of the COVID-19 Pandemic has affected customers' ability to pay their energy bills with commensurate short-term working capital impacts. The Corporation's utilities have instituted various customer relief initiatives, including the temporary suspension of non-payment disconnects and late fees, delayed customer rate increases and the deferred recovery of costs. The Corporation has seen an increase in accounts receivable and, accordingly, its allowance for credit losses in 2020. While not material to Fortis, UNS Energy and Central Hudson, in particular, experienced an increase in credit loss expense in 2020 associated with slower customer collections largely due to the COVID-19 Pandemic. See Note 6 in the 2020 Annual Financial Statements.

The unfavourable impact on cash flow in 2020 associated with slower collection of customer balances was offset by other changes in Operating Cash Flow (see "Performance at a Glance - Operating Cash Flow" on page 7).

Regulatory Matters
Regulator and other stakeholder work schedule disruptions caused delays and postponements for certain regulatory proceedings in 2020. See "Regulatory Highlights" on page 15. The Corporation's significant regulatory proceedings, as discussed below, were concluded by the end of 2020.

Pension Plans
The Corporation's exposure to changes in pension expense is limited by regulatory mechanisms which cover approximately 80% of defined benefit pension plans. The remaining 20% relates primarily to UNS Energy and its exposure is largely attributable to the use of a historical test year in setting rates.

Based upon pension plan valuations as at December 31, 2020, the change in pension expense at UNS Energy in 2021, as compared to 2020, is not material to Fortis.

Outlook
The continued uncertainty surrounding the evolution of the pandemic makes it difficult to predict the ultimate operational and financial impacts on Fortis. Potential impacts are discussed under "Business Risks" on page 28.

Significant Regulatory Decisions

TEP Rate Order
In December 2020, the ACC issued a rate order on TEP's general rate application establishing new customer rates effective January 1, 2021, including: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a Rate Base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River Unit 2 and 10 RICE Units.

FortisAlberta 2021 GCOC
In October 2020, the AUC concluded the 2021 GCOC proceeding and set the ROE for 2021 at 8.50% using a capital structure of 37% common equity, consistent with 2020.

November 2020 AUC Decision
In November 2020, the AUC issued a decision with respect to the 2018 Independent System Operator Tariff Application reversing proposed changes to the AESO's customer contribution policy. This resulted in FortisAlberta retaining approximately $400 million of unamortized customer contributions in its Rate Base.

See "Regulatory Highlights" on page 15 for further information on these significant regulatory developments.

PERFORMANCE AT A GLANCE

Key Financial Metrics *($ millions, except as indicated)*	**2020**	2019	Variance
Common Equity Earnings			
Actual	**1,209**	1,655	(446)
Adjusted [1]	**1,195**	1,115	80
Basic EPS *($)*			
Actual	**2.60**	3.79	(1.19)
Adjusted [1]	**2.57**	2.55	0.02
Dividends			
Paid per Common Share *($)*	**1.9375**	1.8275	0.11
Actual Payout Ratio *(%)*	**74.5**	48.2	26.3
Adjusted Payout Ratio (%) [1]	**75.4**	71.7	3.7
Weighted Average Number of Common Shares Outstanding *(millions)*	**464.8**	436.8	28
Operating Cash Flow	**2,701**	2,663	38
Capital Expenditures [2]	**4,177**	3,818	359

[1] *See "Non-US GAAP Financial Measures" on page 15*
[2] *Includes Fortis' $138 million share of development costs and capital spending for the Wataynikaneyap Transmission Power Project*

TSR [1] *(%)*	**1-Year**	**3-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**—**	**8.0**	**10.9**	**8.3**	**13.3**

[1] *Annualized TSR per Bloomberg, as at December 31, 2020*

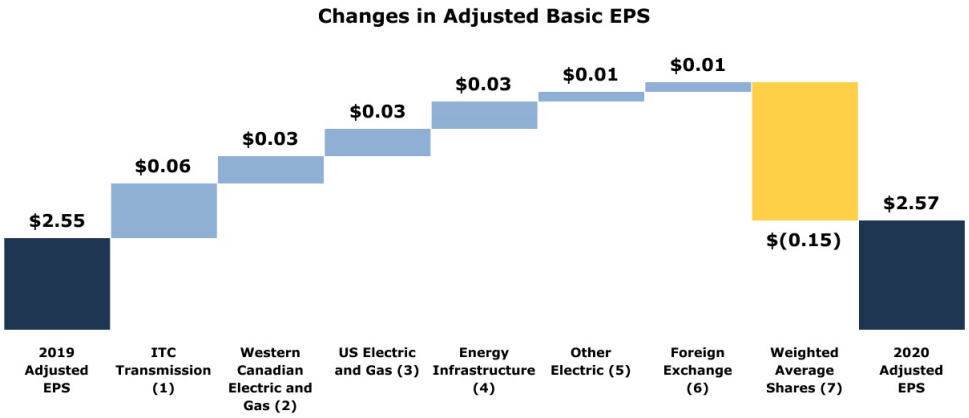
Earnings and EPS

The $446 million decrease in Common Equity Earnings reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the November 2019 and May 2020 FERC decisions at ITC (see "Regulatory Highlights" on page 15).

Excluding the significant one-time items, the Corporation delivered higher earnings of $94 million in 2020 reflecting: (i) Rate Base growth of 8.2%; (ii) increased retail electricity sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. Earnings were also favourably impacted by mark-to-market accounting of natural gas derivatives at Aitken Creek which resulted in unrealized losses of $15 million in 2019 compared to unrealized gains of less than $1 million in 2020. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates in 2020; and (ii) the impact of the COVID-19 Pandemic, reflecting lower sales in the Caribbean and higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

In addition to the above-noted items impacting earnings, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $80 million and $0.02, respectively. Refer to "Non-US GAAP Financial Measures" on page 15 for a reconciliation of these measures. The changes in Adjusted Basic EPS are illustrated in the chart below.



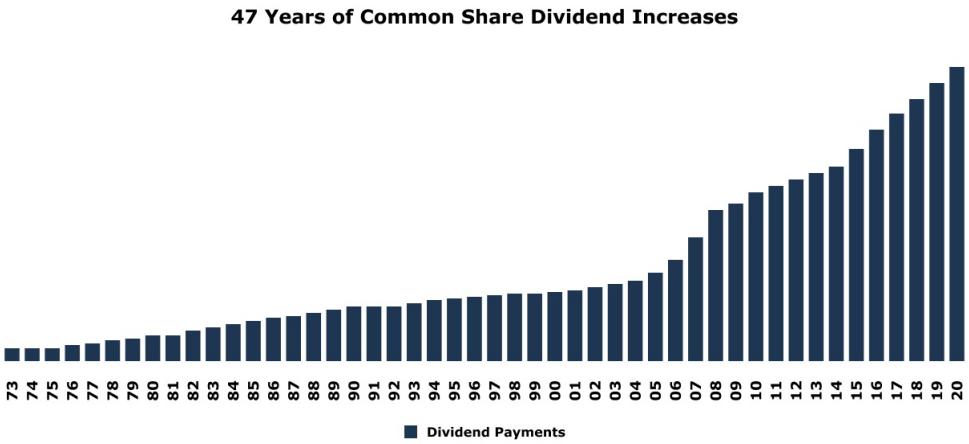
(1) *Primarily reflects Rate Base growth and an increase in the base ROE*
(2) *FortisBC Energy, FortisBC Electric and FortisAlberta. Primarily reflects Rate Base and customer growth, partially offset by the elimination of the PBR efficiency carry-over mechanism at FortisAlberta*
(3) *UNS Energy and Central Hudson. Increase at UNS Energy reflects higher retail sales driven by favourable weather, partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates and higher net operational costs associated with the COVID-19 Pandemic. Increase at Central Hudson reflects Rate Base growth, partially offset by higher net operational expenses associated with the COVID-19 Pandemic.*
(4) *Primarily reflects increased hydroelectric production in Belize due to higher rainfall. Excludes the impact of the disposition of the Waneta Expansion, which was neutral on consolidated earnings.*
(5) *Primarily reflects higher equity income from Belize Electricity and Rate Base growth, partially offset by the impacts of the COVID-19 Pandemic, particularly in the Caribbean*
(6) *Average foreign exchange rate of $1.34 in 2020 compared to $1.33 in 2019*
(7) *Weighted average shares of 464.8 million in 2020 compared to 436.8 million in 2019*

Dividends and TSR
Fortis paid a dividend of $0.505 per common share in the fourth quarter of 2020, up from $0.4775 paid in each of the previous four quarters.

The total 2020 dividend paid per common share was $1.9375, up $0.11 or 6.0% from 2019 and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 74.5% in 2020 compared to 48.2% in 2019 and an annual average of 65.5% over the five-year period of 2016 through 2020. The lower Actual Payout Ratio in 2019 was driven by the gain on the disposition of the Waneta Expansion.

Fortis has increased its common share dividend for 47 consecutive years. The one-year TSR was flat reflecting market conditions in 2020. Growth of dividends and the market price of the Corporation's common shares have together yielded a three-year, five-year, 10-year and 20-year TSR of 8.0%, 10.9%, 8.3% and 13.3%, respectively.

In September 2020 Fortis extended its targeted average annual dividend growth of approximately 6% through 2025.



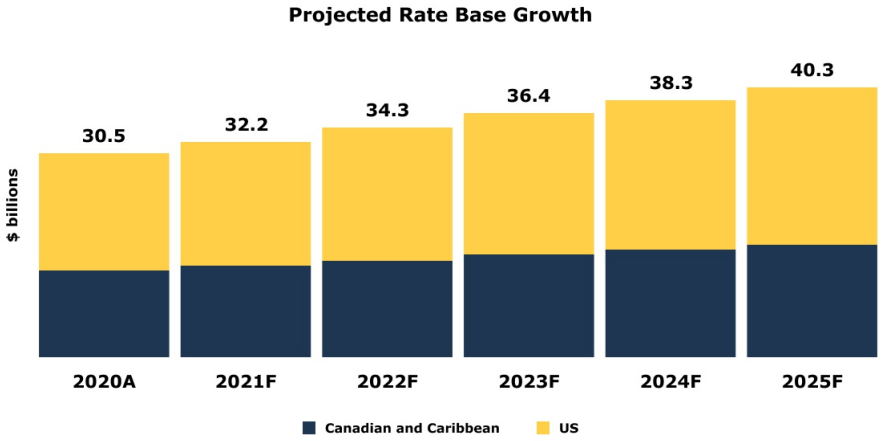
Operating Cash Flow
The $38 million increase in Operating Cash Flow was driven by higher cash earnings reflecting Rate Base growth, higher retail sales and fuel and non-fuel cost recoveries at UNS Energy, and an upfront payment received by FortisAlberta associated with a long-term energy retailer agreement. These were partially offset by: (i) higher transmission cost payments at FortisAlberta; (ii) the timing of recovery of higher gas costs at FortisBC Energy; and (iii) slower collections from customers due to the COVID-19 Pandemic.

Capital Expenditures
Capital expenditures in 2020 were $4.2 billion, $0.4 billion higher than in 2019 and broadly consistent with the 2020 capital plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 24.

The Corporation's five-year 2021-2025 capital plan is targeted at $19.6 billion, $0.8 billion higher than the 2020-2024 capital plan of $18.8 billion disclosed in the 2019 MD&A. The increase is largely due to: (i) two new major capital projects at FortisBC Energy including the Tilbury LNG Resiliency Tank project and the AMI project, with total expected capital spend of approximately $500 million; (ii) $200 million of additional investment in information technology systems and storm hardening at Central Hudson; and (iii) $100 million of interconnections and system rebuilds to provide additional capacity and other improvements at ITC.

The Corporation currently does not expect the COVID-19 Pandemic to impact its overall five-year capital plan.Funding of the capital plan is expected to be primarily through Operating Cash Flow, regulated utility debt and common equity from the Corporation's DRIP.

The five-year capital plan is expected to increase midyear Rate Base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, representing three- and five-year CAGRs of approximately 6.5% and 6.0%, respectively. Fortis expects this growth in Rate Base will support earnings and dividend growth.



Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: 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 infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American energy industry continues to transform. There is an understanding of the impacts of climate change and the need for an energy future with reduced carbon emissions. This creates the need for cleaner energy and energy conservation initiatives to preserve the environment for future generations. The trend toward carbon reduction creates the need for further technological advancements and has heightened customer expectations for cleaner energy. Renewable generation is key to a decarbonized future, with natural gas continuing as a key part of the energy mix. Over the long term, the use of hydrogen may also contribute to carbon reduction. Each of these factors, as well as the increasing affordability of cleaner energy, is driving significant investment opportunity in the utility sector.

Energy policies at the federal, state and provincial levels also reflect the rising focus on climate change, with clean energy and carbon reduction initiatives at the forefront. 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 solar and wind, as well as transmission infrastructure to interconnect renewable energy sources to the grid. Investment opportunities in storage are also growing with the proliferation of various renewable generation sources and decreasing costs of energy storage technology. The electrification of the transportation sector is a significant opportunity for reducing GHG emissions. 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, additional grid automation, 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. Grid hardening and resiliency technology investments are increasing in importance due to climate volatility resulting from more frequent and severe storms, hurricanes and wildfires.

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 investment in cyber- and physical security systems.

The COVID-19 Pandemic has created a number of challenges for the industry, including the need for remote and socially-distanced work environments. Technological advances in communications, videoconferencing, and information sharing have enabled Fortis, and the industry, to maintain productivity and safe, reliable service to customers.

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. Our utilities are capitalizing on this as an investment opportunity to provide enhanced customer information systems and digital technologies to improve customer service.

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, to work with regulators on energy and service solutions, and to be an industry leader in clean energy. Fortis' culture of innovation underlies a continuous drive to find a better way to safely, reliably and affordably deliver the energy and services that customers want and need. To further advance innovation, Fortis is a strategic partner in the Energy Impact Partners utility coalition, which is a strategic private equity fund that invests in emerging technologies, products, services and business models that are transforming the industry. By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

OPERATING RESULTS

($ millions)	**2020**	2019	Variance FX	Variance Other
Revenue	**8,935**	8,783	59	93
Energy Supply Costs	**2,562**	2,520	14	28
Operating Expenses	**2,437**	2,452	19	(34)
Depreciation and Amortization	**1,428**	1,350	8	70
Gain on Disposition	**—**	577	—	(577)
Other Income, Net	**154**	138	(2)	18
Finance Charges	**1,042**	1,035	8	(1)
Income Tax Expense	**231**	289	—	(58)
Net Earnings	**1,389**	1,852	8	(471)
Net Earnings Attributable to:				
Non-Controlling Interests	**115**	130	1	(16)
Preference Equity Shareholders	**65**	67	—	(2)
Common Equity Shareholders	**1,209**	1,655	7	(453)
Net Earnings	**1,389**	1,852	8	(471)

Revenue
The increase in revenue was due primarily to: (i) overall higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) higher retail electricity sales driven by favourable weather in Arizona; and (iv) a $40 million favourable base ROE adjustment at ITC related to prior periods as a result of the May 2020 FERC decision. The increase was partially offset by: (i) a $91 million favourable base ROE adjustment at ITC in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower short-term wholesale sales at UNS Energy. See "Regulatory Highlights" on page 15 for further details on the November 2019 and May 2020 FERC decisions.

Energy Supply Costs
The increase in energy supply costs was due primarily to overall higher commodity costs, partially offset by the impact of lower wholesale sales at UNS Energy.

Operating Expenses
The decrease in operating expenses was due primarily to: (i) lower recoverable operating expenses at ITC due to temporary cost saving measures implemented in response to the COVID-19 Pandemic; and (ii) lower flow-through costs at TEP associated with Springerville Units 3 and 4. The decrease was partially offset by higher operating expenses at Central Hudson associated with general inflationary increases and storm events. UNS Energy and Central Hudson also had higher expenses in 2020 related to the COVID-19 Pandemic including an increase in credit loss expense.

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

Gain on Disposition
The gain recorded in 2019 reflects the April 2019 disposition of the Waneta Expansion.

Other Income, Net
The increase in other income, net was due primarily to: (i) higher equity income from Belize Electricity; and (ii) the impact of non-service pension costs, partially offset by; (iii) an $11 million gain recognized in 2019 on the repayment of US$400 million of debt via tender offer.

Finance Charges
Finance charges were comparable to 2019. An increase in finance charges associated with continued capital investment was offset mainly by lower finance charges at Corporate due to the repayment of debt in 2019 using proceeds from the Waneta Expansion disposition and the $1.2 billion common equity offering.

Income Tax Expense
The decrease in income tax expense was driven by tax recorded in 2019 upon the disposition of the Waneta Expansion, partially offset by the impact of higher valuation allowances released in 2019.

Net Earnings
See "Performance at a Glance - Earnings and EPS" on page 5.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings				
			Variance	
($ millions)	**2020**	2019	FX [1]	Other
Regulated Utilities				
ITC	**449**	471	8	(30)
UNS Energy	**302**	292	4	6
Central Hudson	**91**	85	—	6
FortisBC Energy	**175**	165	—	10
FortisAlberta	**133**	131	—	2
FortisBC Electric	**56**	54	—	2
Other Electric [2]	**112**	106	—	6
	1,318	1,304	12	2
Non-Regulated				
Energy Infrastructure [3]	**39**	18	—	21
Corporate and Other [4]	**(148)**	333	(5)	(476)
Common Equity Earnings	**1,209**	1,655	7	(453)

[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] *Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Caribbean Utilities; FortisTCI; and Belize Electricity*
[3] *Primarily consists of long-term contracted generation assets in Belize, Aitken Creek in British Columbia and, until its April 16, 2019 disposition, the Waneta Expansion*
[4] *Includes Fortis net corporate expenses and non-regulated holding company expenses*

ITC			Variance	
($ millions)	**2020**	2019	FX	Other
Revenue [(1)]	**1,744**	1,761	22	(39)
Earnings [(1)]	**449**	471	8	(30)

(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 decrease in revenue, net of foreign exchange, was due primarily to: (i) a $91 million favourable base ROE adjustment recorded in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower recoverable operating expenses due to cost saving measures implemented in response to the COVID-19 Pandemic. The decrease was partially offset by: (i) a $40 million favourable base ROE adjustment recorded in 2020 related to prior periods as a result of the May 2020 FERC decision; (ii) Rate Base growth; and (iii) an increase in the base ROE compared to 2019.

Earnings
The decrease in earnings, net of foreign exchange, was due to significant one-time items related to the reversal of prior period liabilities as a result of the base ROE decisions made by FERC in November 2019 and May 2020. The year over year impact of these one-time items was $56 million reflecting the net of: (i) an $83 million favourable adjustment in 2019; and (ii) a $27 million favourable adjustment in 2020. Excluding this impact, earnings from ITC grew by $26 million in 2020 reflecting growth in Rate Base, an increase in the base ROE compared to 2019, and lower business development costs.

See "Regulatory Highlights" on page 15 for further information on the November 2019 and May 2020 FERC decisions.

UNS Energy			Variance	
	2020	2019	FX	Other
Retail electricity sales *(GWh)*	**10,920**	10,431	—	489
Wholesale electricity sales *(GWh)* [(1)]	**5,843**	7,923	—	(2,080)
Gas sales *(PJ)*	**15**	16	—	(1)
Revenue *($ millions)*	**2,260**	2,212	24	24
Earnings *($ millions)*	**302**	292	4	6

(1) *Primarily short-term wholesale sales*

Sales
The increase in retail electricity sales was due primarily to higher air conditioning load as a result of warmer temperatures in 2020 as compared to unseasonably cool temperatures in 2019. The COVID-19 Pandemic has not had a material impact on sales as the decrease in consumption by commercial and industrial customers, due to the temporary closure of non-essential businesses, was offset by an increase in consumption by residential customers, due to work-from-home practices.

The decrease in wholesale electricity sales was due primarily to the expiration of a short-term capacity sales transaction, which was established to offset costs associated with a Gila River Unit 2 tolling PPA during 2019. The capacity sales transaction ended in December 2019 with the purchase of Gila River Unit 2. Revenue from short-term wholesale sales is primarily credited to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

Gas sales were comparable to 2019.

Revenue
The increase in revenue, net of foreign exchange, was due primarily to higher revenue related to the recovery of fuel and non-fuel costs through the normal operation of regulatory mechanisms and higher retail sales mainly driven by weather. The increase was partially offset by lower short-term wholesale sales and a decrease in flow-through costs related to Springerville Units 3 and 4.

Earnings
The increase in earnings, net of foreign exchange, was due primarily to higher retail electricity sales, partially offset by higher costs associated with Rate Base growth not reflected in customer rates in 2020. Beginning January 1, 2021, new customer rates are in effect following the conclusion of TEP's general rate application (see "Regulatory Highlights" on page 15). Higher net operational expenses associated with the COVID-19 Pandemic, including an increase in credit loss expense, also unfavourably impacted earnings.

Central Hudson			Variance	
	2020	2019	FX	Other
Electricity sales *(GWh)*	**4,969**	4,963	—	6
Gas sales *(PJ)*	**23**	22	—	1
Revenue *($ millions)*	**953**	917	9	27
Earnings *($ millions)*	**91**	85	—	6

Sales
Electricity sales were comparable to 2019. Higher average consumption by residential customers was largely offset by lower average consumption by commercial customers, both as a result of the COVID-19 Pandemic.

Gas sales were comparable to 2019.

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

Revenue
The increase in revenue, net of foreign exchange, was due primarily to an increase in gas and electricity delivery rates effective July 1, 2019 and July 1, 2020, reflecting a return on increased Rate Base assets as well as the recovery of higher operating and financing expenses (see "Regulatory Highlights" on page 15 for information on the July 1, 2020 rate increase). The increase was partially offset by the flow through of lower energy supply costs.

Earnings
The increase in earnings was due primarily to Rate Base growth, partially offset by higher net operational expenses associated with the COVID-19 Pandemic, including an increase in credit loss expense.

FortisBC Energy	**2020**	2019	Variance
Gas sales *(PJ)*	**219**	227	(8)
Revenue *($ millions)*	**1,385**	1,331	54
Earnings *($ millions)*	**175**	165	10

Sales
The decrease in gas sales was due primarily to lower consumption by transportation customers, partially offset by higher consumption from residential customers, due partly to work-from-home practices as a result of the COVID-19 Pandemic.

Revenue
The increase in revenue was due primarily to a higher cost of natural gas to be recovered from customers and Rate Base growth.

Earnings
The increase in earnings 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 delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

FortisAlberta	2020	2019	Variance
Electricity deliveries *(GWh)*	**16,092**	16,887	(795)
Revenue *($ millions)*	**596**	598	(2)
Earnings *($ millions)*	**133**	131	2

Deliveries
The decrease in electricity deliveries was due to lower average consumption by oil and gas and commercial customers, largely associated with the COVID-19 Pandemic and the downturn in the oil and gas sector. The decrease was partially offset by customer additions and higher average consumption by residential customers reflecting work-from-home practices as a result of the COVID-19 Pandemic.

As more than 85% 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 decrease in revenue was due primarily to: (i) the impact of the AUC's November 2020 decision with respect to the 2018 Independent System Operator Tariff Application reflecting the flow through of lower depreciation costs with no material impact on earnings (see "Regulatory Highlights" on page 15); and (ii) the recognition of revenue in 2019 associated with the PBR efficiency carry-over mechanism. The decrease was partially offset by Rate Base growth and customer additions.

Earnings
The increase in earnings was due primarily to Rate Base growth, customer additions and a lower deferred tax expense due to the utilization of tax loss carryforwards in 2019. The increase was partially offset by higher operating expenses and the impact of the PBR efficiency carry-over mechanism.

FortisBC Electric	2020	2019	Variance
Electricity sales *(GWh)*	**3,291**	3,326	(35)
Revenue *($ millions)*	**424**	418	6
Earnings *($ millions)*	**56**	54	2

Sales
The decrease in electricity sales was due to lower average consumption by commercial and industrial customers, partially offset by higher average residential consumption, both due to the impact of the COVID-19 Pandemic.

Revenue
The increase in revenue was due primarily to higher third-party contract work and Rate Base growth, partially offset by the absence of revenue associated with the provision of operating, maintenance and management services to the Waneta Expansion, which was sold in April 2019.

Earnings
The increase in earnings was due primarily to Rate Base growth, partially offset by the sale of the Waneta Expansion, discussed above.

Due to regulatory deferral mechanisms, changes in consumption levels do not materially impact earnings.

Other Electric			Variance	
	2020	2019	FX	Other
Electricity sales *(GWh)*	**9,175**	9,366	—	(191)
Revenue *($ millions)*	**1,485**	1,467	4	14
Earnings *($ millions)*	**112**	106	—	6

Sales
The decrease in electricity sales was due primarily to overall lower average consumption driven by the COVID-19 Pandemic, largely reflecting the temporary closure of non-essential businesses and border closures affecting tourism-related sales in the Caribbean.

Revenue
The increase in revenue, net of foreign exchange, was due primarily to the flow through of overall higher energy supply costs and Rate Base growth, partially offset by lower sales.

Earnings
The increase in earnings was due to higher equity income from Belize Electricity and Rate Base growth, partially offset by the impact of the COVID-19 Pandemic, largely reflecting lower sales in the Caribbean.

Energy Infrastructure	**2020**	2019	Variance
Electricity sales *(GWh)*	**229**	144	85
Revenue *($ millions)*	**88**	82	6
Earnings *($ millions)*	**39**	18	21

Sales
The increase in electricity sales reflected increased hydroelectric production in Belize due to higher rainfall levels, partially offset by the Waneta Expansion disposition in 2019, which contributed sales of 80 GWh in that year.

Revenue and Earnings
The increases in revenue and earnings reflected: (i) higher hydroelectric production in Belize; and (ii) the favourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek which resulted in unrealized losses of $15 million in 2019 compared to unrealized gains of less than $1 million in 2020. The increases in revenue and earnings were partially offset by the Waneta Expansion disposition in 2019.

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 resultant earnings volatility can be significant.

Corporate and Other			Variance	
($ millions)	**2020**	2019	FX	Other
Net (expenses) income	**(148)**	333	(5)	(476)

The increase in net expenses was due to one-time items: (i) the net after-tax gain of $484 million on the April 2019 disposition of the Waneta Expansion; and (ii) a $7 million gain on the repayment of debt recognized in 2019. Excluding these one-time items, Corporate expenses, net of foreign exchange, decreased by $10 million. The decrease was driven by lower finance charges, due to the repayment of debt using proceeds from the Waneta Expansion disposition and the $1.2 billion common equity offering, and lower operating expenses, partially offset by an increase in tax expense due to valuation allowances released in 2019.

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 the removal of items that management excludes in its key decision-making processes and evaluation of operating results, and are reconciled as follows.

Non-US GAAP Reconciliation			
($ millions, except as shown)	**2020**	2019	Variance
Common Equity Earnings	**1,209**	1,655	(446)
Adjusting items:			
FERC base ROE decisions [(1)]	**(27)**	(83)	56
US tax reform [(2)]	**13**	12	1
Unrealized loss on mark-to-market of derivatives[(3)]	**—**	15	(15)
Gain on disposition [(4)]	**—**	(484)	484
Adjusted Common Equity Earnings	**1,195**	1,115	80
Adjusted Basic EPS *($)*	**2.57**	2.55	0.02

(1) *Represents prior period impacts of the May 2020 and November 2019 FERC base ROE decisions, respectively (see "Regulatory Highlights" below), included in the ITC segment*
(2) *The finalization of US tax reform regulations associated with anti-hybrid regulations in 2020 and base-erosion and anti-abuse tax in 2019, included in the Corporate and Other segment*
(3) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment*
(4) *Gain on sale of the Waneta Expansion, net of expenses, in April 2019, included in the Corporate and Other segment*

REGULATORY HIGHLIGHTS

General

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. PBR mechanisms generally apply a formula that incorporates 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 governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2020 Annual Financial Statements. Also refer to "Business Risks - Regulation" on page 28.

COVID-19 Pandemic Impacts
The COVID-19 Pandemic resulted in several customer relief initiatives as well as the delay and postponement of several regulatory proceedings in 2020, as described below. The Corporation's significant regulatory proceedings, including TEP's general rate application as well as FortisAlberta's 2021 GCOC and AESO customer contribution proceedings, were concluded by the end of 2020.

Customer Relief Initiatives

UNS Energy
Pursuant to the ACC's approval of the utility's customer relief initiatives, TEP refunded to customers approximately $11 million of collected demand side management funds in excess of program costs.

In December 2020, the ACC enacted a bill credit and payment program for residential electric customers who are behind on their electric bills as a result of the COVID-19 Pandemic, including automatic enrollment into an eight-month payment plan for qualified customers. TEP voluntarily created payment arrangements for commercial customers.

Central Hudson
In March 2020, as agreed with the PSC, Central Hudson postponed the collection in customer rates of approximately $4 million of deferred costs related mainly to environmental remediation until July 1, 2021.

FortisBC Energy and FortisBC Electric
In April 2020, pursuant to the BCUC's approval of the utilities' customer relief initiatives, FortisBC Energy and FortisBC Electric implemented three-month bill deferrals for certain customer classes, the repayment of which commenced in the third quarter of 2020. The BCUC also authorized the deferral of otherwise uncollectible revenue from customers, the recovery of which will be determined through a future rate filing once the financial impact of the pandemic is known.

Delayed and Postponed Regulatory Proceedings

UNS Energy
General Rate Application: TEP filed a rate application in April 2019 based on a 2018 test year. In December 2020 the ACC issued a rate order including new customer rates effective January 1, 2021. Provisions of the order include: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a Rate Base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River Unit 2 and 10 RICE Units.

Central Hudson
2020 Rates: In June 2020, the PSC approved Central Hudson's request to postpone scheduled electric and gas delivery rate increases, reflecting an increase in the equity component of its capital structure from 49% to 50%, from July 1, 2020 to October 1, 2020. The deferred revenue associated with the delay is being collected over the nine-month period to June 30, 2021.

COVID-19 Proceeding: In June 2020, the PSC initiated a generic proceeding to identify and address the effects of the COVID-19 Pandemic. The outcome of this proceeding and potential impacts, if any, are unknown at this time.

FortisAlberta
Generic Cost of Capital Proceeding: In December 2018, the AUC initiated a GCOC proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes were necessary for determining capital structure in years in which a ROE formula is in place. In October 2020, given the time that had passed since initiation of the proceeding and ongoing economic uncertainty, the AUC concluded the proceeding and set the ROE for 2021 at 8.50% using a capital structure of 37% common equity, consistent with 2020. In December 2020, the AUC initiated a new GCOC proceeding to establish the cost of capital parameters for 2022 and possibly one or more future years. This proceeding is expected to be ongoing throughout 2021.

Other Electric

Caribbean Utilities: In August 2020, the Utility Regulation and Competition Office approved the postponement of Caribbean Utilities' scheduled June 1, 2020 annual rate adjustment to January 1, 2021 to provide customer relief from the economic effects of the COVID-19 Pandemic. The deferred revenue associated with the delay is being collected over a two-year period beginning January 2021.

FortisTCI: In February 2020, the Government of the Turks and Caicos Islands approved a 6.8% average increase in FortisTCI's electricity rates, effective April 1, 2020, including the recovery of hurricane-related costs incurred in 2017. In March 2020, to provide customer relief from the economic effects of the COVID-19 Pandemic, the effective date was postponed and new rates became effective July 22, 2020.

FortisTCI sought regulatory approval to defer its incremental operating expenses associated with the COVID-19 Pandemic. Approval was granted in December 2020 to allow the deferral of approximately $1.5 million in costs, to be amortized over the remaining 15-year life of FortisTCI's licence.

Significant Regulatory Developments

ITC

ROE Complaints: In May 2020, FERC issued an order on the rehearing of its November 2019 decision on the MISO transmission owner ROE complaints and set the base ROE for the periods from November 2013 through February 2015 and from September 2016 onward at 10.02%, up to a maximum of 12.62% with incentive adders. This represents an increase from the base ROE of 9.88%, up to a maximum of 12.24% with incentive adders, determined in FERC's November 2019 decision. Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the MISO region of 10.77%, up from 10.63% as set in the November 2019 decision.

Net regulatory liabilities of $6 million and $91 million were recorded at December 31, 2020 and 2019, respectively, reflecting: (i) the terms of the May 2020 and November 2019 decisions; and (ii) $42 million refunded to customers in 2020. The May 2020 FERC decision resulted in an increase in Fortis' net earnings of $29 million in 2020, including $27 million related to the reversal of liabilities established in prior periods (2019 - November 2019 FERC decision increased Fortis' net earnings by $63 million, including $83 million related to the reversal of liabilities established in prior periods).

Review of Transmission Incentives Policy: In March 2020, FERC issued a NOPR proposing to update its transmission incentives policy for transmission owners, including ITC, to grant incentives to projects based upon benefits to customers regarding reliability and cost savings through the reduction of transmission congestion. FERC proposed total ROE incentives of up to 250 basis points that would not be limited by the upper end of the base ROE zone of reasonableness. The NOPR also proposed, among other things, to eliminate the ROE adder for independent transmission ownership, and to increase the ROE adder for regional transmission owner participation. Comments from stakeholders, including ITC, were provided to FERC through July 2020. The outcome of these proceedings may impact future incentive adders that are included in transmission rates charged by transmission owners, including ITC.

Central Hudson

General Rate Application: In August 2020, Central Hudson filed a rate application with the PSC requesting an increase in electric and natural gas delivery revenue of $44 million and $19 million, respectively, effective July 1, 2021. An order from the PSC is expected in 2021.

FortisBC Energy and FortisBC Electric

Multi-Year Rate Plan Applications: In June 2020, the BCUC issued a decision on FortisBC Energy's and FortisBC Electric's MRP for 2020 to 2024. The decision sets the rate-setting framework for the five-year period including: (i) the level of operation and maintenance expense and growth capital to be included in customer rates, indexed for inflation less a fixed productivity adjustment factor; (ii) a forecast approach to sustainment capital; (iii) an innovation fund recognizing the need to accelerate investment in clean energy innovation; and (iv) a 50/50 sharing between customers and the utilities of variances from the allowed ROE. In the fourth quarter of 2020, the BCUC approved: (i) the January 1, 2020 delivery rate increase; and (ii) an increase in 2021 delivery rates, effective January 1, 2021, reflecting the terms of this decision.

Generic Cost of Capital Proceeding: In January 2021, the BCUC issued a notice that a GCOC proceeding will be initiated in the second quarter of 2021 and will include a review of the common equity component of capital structure and the allowed ROE effective January 1, 2022.

FortisAlberta

2018 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 ("ACCP") is accounted for between distribution facility owners, such as FortisAlberta, and TFOs. The decision prevented any future investment by FortisAlberta under the policy and directed 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 November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

The AUC initiated a new proceeding in November 2020 to consider whether the ACCP should be modified on a prospective basis. A decision is expectein the second quarter of 2021.

FINANCIAL POSITION

Significant Changes between December 31, 2020 and 2019			
	Increase (Decrease)		
	FX	**Other**	
Balance Sheet Account	*($ millions)*	*($ millions)*	**Explanation**
Cash and cash equivalents	(3)	(118)	Related to the timing of debt and equity issuances, and the related reinvestment in capital and operating requirements.
Regulatory assets (current and long-term)	(25)	230	Due primarily to deferred income taxes, and the operation of energy management cost and employee future benefits deferrals, partially offset by lower derivative loss deferrals at UNS Energy.
Property, plant and equipment, net	(425)	2,435	Due to capital expenditures, partially offset by depreciation.
Goodwill	(212)	—	
Short-term borrowings	(10)	(370)	Reflects the repayment of short-term borrowings at UNS Energy and commercial paper at ITC.
Other liabilities	(16)	169	Reflects employee future benefits, refundable deposits received by ITC for transmission network upgrades, and an upfront payment received by FortisAlberta associated with a long-term energy retailer agreement.
Regulatory liabilities (current and long-term)	(48)	(207)	Due to ROE complaints liability at ITC, deferred income taxes, and the normal operation of rate stabilization and related accounts.
Deferred income tax liabilities	(34)	409	Due to higher temporary differences associated with ongoing capital investment.

Significant Changes between December 31, 2020 and 2019			
	Increase (Decrease)		
	FX	Other	
Balance Sheet Account	*($ millions)*	*($ millions)*	**Explanation**
Long-term debt (including current portion)	(296)	2,472	Reflects debt issuances, partially offset by debt repayments at the regulated utilities, largely at ITC and UNS Energy.
Shareholders' equity	(279)	445	Due primarily to: (i) Common Equity Earnings for 2020, less dividends declared on common shares; and (ii) the issuance of common shares.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will be paid from Operating Cash Flow, with varying levels of residual cash flow 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 and there could be higher-than-normal working capital deficiencies in the short term, as the ongoing impacts of the COVID-19 Pandemic affects customers' ability to pay their energy bills. See "Business Risks" on page 28.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's committed credit facility, proceeds from the DRIP and issuances of common shares, preference equity and long-term debt. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. 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 and to refinance maturing debt.

Although Fortis and its utilities continue to be successful in accessing capital markets, the ability to access cash through capital markets may be impacted by the COVID-19 Pandemic.

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than approximately 25% of the total facilities. Approximately $5.3 billion of the total credit facilities are committed with maturities ranging from 2021 through 2025. Available credit facilities are summarized in the following table.

Credit Facilities				
As at December 31	Regulated	Corporate		
($ millions)	Utilities	and Other	**2020**	2019
Total credit facilities [(1)]	3,700	1,881	**5,581**	5,590
Credit facilities utilized:				
Short-term borrowings	(132)	—	**(132)**	(512)
Long-term debt (including current portion)	(714)	(266)	**(980)**	(640)
Letters of credit outstanding	(77)	(53)	**(130)**	(114)
Credit facilities unutilized	2,777	1,562	**4,339**	4,324

(1) *Additional information about these credit facilities is provided in Note 14 in the 2020 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.

As at December 31, 2020, consolidated fixed-term debt maturities/repayments are expected to average $891 million annually over the next five years and approximately 81% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In December 2020, 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 $2.0 billion. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity due, in part, to its $1.2 billion common equity offering and sale of the Waneta Expansion in 2019. See "Cash Flow Summary - Financing Activities" on page 20.

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 currently expect to continue to have reasonable access to long-term capital in 2021.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2020 and are expected to remain compliant in 2021.

CASH FLOW SUMMARY

Summary of Cash Flows			
Years ended December 31			
($ millions)	**2020**	2019	Variance
Cash, beginning of year	**370**	332	38
Cash provided from (used in):			
Operating activities	**2,701**	2,663	38
Investing activities	**(4,132)**	(2,768)	(1,364)
Financing activities	**1,327**	154	1,173
Effect of exchange rate changes on cash and cash equivalents	**(17)**	(26)	9
Cash and change in cash associated with assets held for sale	**—**	15	(15)
Cash, end of year	**249**	370	(121)

Operating Activities
See "Performance at a Glance - Operating Cash Flow" on page 7.

Investing Activities
Cash used in investing activities reflects higher capital expenditures in 2020. See "Performance at a Glance - Capital Expenditures" on page 7 and "Capital Plan" on page 24. Cash used in investing activities in 2019 was partially offset by proceeds from the Waneta Expansion disposition.

Financing Activities
Cash flow related to financing activities will fluctuate largely as a result of changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, which together impact the amount of funding required from debt and common equity issuances. See "Cash Flow Requirements" on page 19.

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. Also in 2019, net proceeds of $995 million from the April 2019 Waneta Expansion disposition 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, 2020

($ millions, except %)	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount**	**Use of Proceeds**
ITC						
Unsecured term loan credit agreement	January	*(1)*	2021	US	75	*(2)(3)*
Unsecured term loan credit agreement *(4)*	January	*(5)*	2021	US	200	*(4)*
Unsecured senior notes	May	2.95	2030	US	700	*(2)(3)(6)*
First mortgage bonds	July	3.13	2051	US	180	*(2)(3)(7)*
Secured senior notes	October	3.02	2055	US	150	*(2)(3)(7)(8)*
UNS Energy						
Unsecured senior notes	April	4.00	2050	US	350	*(2)(3)*
Unsecured senior notes	August	1.50	2030	US	300	*(7)*
Unsecured senior notes	September	2.17	2032	US	50	*(2)(3)*
Central Hudson						
Unsecured senior notes	May	3.42	2050	US	30	*(3)*
Unsecured senior notes	July	3.62	2060	US	30	*(3)(7)*
Unsecured senior notes	September	2.03	2030	US	40	*(8)*
Unsecured senior notes	November	2.03	2030	US	30	*(3)(7)*
FortisBC Energy						
Unsecured debentures	July	2.54	2050		200	*(7)*
FortisAlberta						
Unsecured senior debentures	December	2.63	2051		175	*(2)*
FortisBC Electric						
Unsecured debentures	May	3.12	2050		75	*(2)*
Newfoundland Power						
First mortgage sinking fund bonds	April	3.61	2060		100	*(2)(3)*
FortisTCI						
Unsecured senior notes	June/October	5.30	2035	US	30	*(7)(8)*
Unsecured senior notes	October/December	3.25	2030	US	10	*(3)*

(1) Floating rate of a one-month LIBOR plus a spread of 0.45%
(2) Repay credit facility borrowings
(3) General corporate purposes
(4) Maximum amount of borrowings under this agreement of US$400 million has been drawn; current period borrowings were used to repay an outstanding commercial paper balance.
(5) Floating rate of a two-month LIBOR plus a spread of 0.60%
(6) Early redemption of unsecured term loan borrowing of US$400 million
(7) Finance capital expenditures
(8) Repay maturing long-term debt

Common Equity Financing

Common Equity Issuances and Dividends Paid Years ended December 31 *($ millions, except as indicated)*	**2020**	2019	Variance
Common shares issued:			
Cash [1]	**58**	1,442	(1,384)
Non-cash [2]	**116**	314	(198)
Total common shares issued	**174**	1,756	(1,582)
Number of common shares issued *(# millions)*	**3.5**	34.8	(31.3)
Common share dividends paid:			
Cash	**(786)**	(494)	(292)
Non-cash [3]	**(114)**	(299)	185
Total common share dividends paid	**(900)**	(793)	(107)
Dividends paid per common share *($)*	**1.9375**	1.8275	0.1100

[1] *Includes common shares issued under stock option and employee share purchase plans. For 2019, mainly reflects the issuance of shares in December 2019 and through the ATM Program.*

[2] *Common shares issued under the DRIP and stock option plan. Effective March 1, 2020, the 2% discount offered on common share issuances under the DRIP was terminated and effective December 1, 2020 was reinstated. See "Cash Flow Requirements" on page 19 for further information.*

[3] *Common share dividends reinvested under the DRIP*

On February 11, 2021, Fortis declared a dividend of $0.505 per common share payable on June 1, 2021.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, 2020		Due					
($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [1]	**24,514**	1,254	823	1,786	1,088	484	19,079
Interest	**16,113**	980	949	919	859	824	11,582
Finance leases [2]	**1,225**	33	34	34	34	34	1,056
Other obligations	**557**	184	112	97	37	37	90
Other commitments: [3]							
Waneta Expansion capacity agreement	**2,576**	52	53	54	55	56	2,306
Gas and fuel purchase obligations	**2,355**	679	453	312	192	124	595
Power purchase obligations	**1,867**	249	208	188	191	180	851
Renewable PPAs	**1,380**	102	102	101	101	101	873
ITC easement agreement	**381**	13	13	13	13	13	316
Debt collection agreement	**112**	3	3	3	3	3	97
Renewable energy credit purchase agreements	**97**	15	14	16	9	7	36
Other	**116**	48	5	4	4	3	52
	51,293	3,612	2,769	3,527	2,586	1,866	36,933

[1] *Amounts not reduced by unamortized deferred financing and discount costs of $147 million. Additional information is provided in Note 14 in the 2020 Annual Financial Statements.*

[2] *Additional information is provided in Note 15 in the 2020 Annual Financial Statements.*

[3] *Additional information is provided in Note 28 in the 2020 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 $3.8 billion for 2021 and approximately $19.6 billion over the five-year 2021-2025 capital plan. See "Capital Plan" on page 24.

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 the 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.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2020, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $94 million, for which it has issued a parental guarantee. As at December 31, 2020, there was no obligation under this guarantee.

As at December 31, 2020, FortisBC Holdings Inc., a non-regulated holding company, had $69 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 $130 million as at December 31, 2020 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 *(%)*		
As at December 31	**2020**	2019
Debt [(1)]	**54.8**	53.1
Preference shares	**3.6**	3.8
Common shareholders' equity and minority interest [(2)]	**41.6**	43.1
	100.0	100.0

(1) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*
(2) *Includes minority interest of 3.5% as at December 31, 2020 (2019 - 3.7%)*

Outstanding Share Data
As at February 11, 2021, the Corporation had issued and outstanding466.8 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.7 million Series H; 2.3 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 11, 2021, an additional 3.3 millioncommon 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 the level of holding company debt.

Credit Ratings			
As at December 31, 2020	**Rating**	**Type**	**Outlook**
S&P	A-	Corporate	Negative
	BBB+	Unsecured debt	
DBRS Morningstar	BBB (high)	Corporate	Positive
	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.

The COVID-19 Pandemic did not have a material impact on capital expenditures in 2020. Capital expenditures of $4.2 billion were broadly consistent with the 2020 capital plan as disclosed in the 2019 MD&A.

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** [2]	**Total**	*(%)*
Generation	—	639	—	—	—	26	42	**707**	**5**	**712**	**17**
Transmission	1,070	84	48	138	—	34	165	**1,539**	**—**	**1,539**	**37**
Distribution	—	330	188	207	333	46	167	**1,271**	**—**	**1,271**	**30**
Other [3]	112	147	103	126	87	29	37	**641**	**14**	**655**	**16**
Total	1,182	1,200	339	471	420	135	411	**4,158**	**19**	**4,177**	**100**
(%)	29	29	8	11	10	3	10	**100**	**—**	**100**	

[1] *Reflects cash outlay for property, plant and equipment and intangible assets as shown on the Consolidated Statements of Cash Flows in the 2020 Annual Financial Statements, as well as Fortis' $138 million share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

[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. The impact of the COVID-19 Pandemic on forecast capital expenditures will continue to be evaluated and, depending on the length and severity of the pandemic, certain planned expenditures may shift within the 2021-2025 capital plan.

Forecast 2021 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	—	117	1	—	—	24	189	**331**	**53**	**384**	**10**
Transmission	949	191	41	168	—	23	310	**1,682**	**—**	**1,682**	**44**
Distribution	—	270	167	184	266	81	173	**1,141**	**—**	**1,141**	**30**
Other	51	171	97	115	80	25	49	**588**	**18**	**606**	**16**
Total	1,000	749	306	467	346	153	721	**3,742**	**71**	**3,813**	**100**
(%)	26	20	8	12	9	4	19	**98**	**2**	**100**	

[1] *Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

Five-Year Capital Plan [1]						
($ billions)	2021	2022	2023	2024	2025	**Total**
	3.8	3.9	3.9	4.0	4.0	**19.6**

[1] *Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

The $19.6 billion five-year capital plan is $0.8 billion higher than the $18.8 billion five-year plan for 2020-2024, as disclosed in the 2019 MD&A. The increase is largely due to: (i) two new major capital projects at FortisBC Energy including the Tilbury LNG Resiliency Tank project and the AMI project, with total expected capital spend of approximately $500 million; (ii) $200 million of additional investment in information technology systems and storm hardening at Central Hudson; and (iii) $100 million of interconnections and system rebuilds to provide additional capacity and other improvements at ITC.

The capital plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 15% 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**	Forecast	Five-Year Plan
(%)	**2020**	2021	2021-2025
Growth [1]	**21**	31	26
Sustaining [2]	**65**	54	58
Other [3]	**14**	15	16
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)	**2020**	2021	2025
ITC	**9.5**	9.9	12.5
UNS Energy	**5.7**	6.2	7.6
Central Hudson	**2.1**	2.3	3.2
FortisBC Energy	**5.1**	5.2	6.8
FortisAlberta	**3.7**	3.8	4.2
FortisBC Electric	**1.4**	1.5	1.7
Other Electric	**3.0**	3.3	4.3
Total	**30.5**	32.2	40.3

[1] *Simple average of Rate Base at beginning and end of the year*

Total midyear Rate Base is forecast to grow to $40.3 billion by 2025 under the five-year capital plan, representing a CAGR of approximately 6.0%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects [1]				Forecast		
($ millions)	Project	Pre-2020	**Actual 2020**	2021	2022-2025	Expected Completion
ITC [2]	Multi-Value Regional Transmission Projects	625	**17**	75	186	2023
	34.5 to 69 kV Transmission Conversion Project	352	**93**	41	107	Post-2025
UNS Energy	Vail-to-Tortolita Project	—	**—**	54	190	2023
	Oso Grande Wind Project	65	**509**	24	—	2021
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade	388	**23**	18	—	2021
	Eagle Mountain Woodfibre Gas Line Project [3]	—	**—**	—	350	2025
	Transmission Integrity Management Capabilities Project	13	**8**	7	434	Post-2025
	Inland Gas Upgrades Project	9	**50**	53	177	2025
	Tilbury 1B	8	**12**	1	375	2025
	Tilbury LNG Resiliency Tank	—	**10**	11	198	Post-2025
	AMI Project	—	**—**	4	243	Post-2025
Other Electric	Wataynikaneyap Transmission Power Project [4]	40	**138**	330	206	2023
Total			**860**	618	2,466	

(1) *Includes applicable AFUDC*
(2) *Pre-2020 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
Four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects were completed pre-2020. The fourth project is expected to be placed in service in 2023.

34.5 to 69kV Transmission Conversion Project
Multiple capital initiatives designed to construct new 69 kV lines, upgrade existing 34.5 kV lines to 69 kV, and complete substation conversions with in service dates ranging from pre-2020 to post-2025.

Vail-to-Tortolita Project
A phase of the Southline Transmission Project that consists of new construction and upgrades to connect existing TEP substations. The project includes the construction of a new 230 kV line within TEP's service territory. Construction is expected to begin in early 2022 with an in-service date of 2023.

Oso Grande Wind Project
Construction of a 750 MW wind-powered electric generating facility that complements UNS Energy's existing renewable solar generation portfolio, of which UNS Energy owns 250 MW. Construction is expected to be completed and the facility placed in service in the first half of 2021.

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 project is substantially complete, with one pipeline segment to be replaced in 2021. Final allowable project costs are subject to review by the BCUC.

Eagle Mountain Woodfibre Gas Line Project
Gas line expansion to a proposed LNG site in Squamish, British Columbia. In March 2020 Woodfibre LNG Limited, the owner of the proposed LNG facility, requested an extension to its British Columbia Environmental Assessment Certificate due to production and supply chain disruptions resulting, in part, from the COVID-19 Pandemic. In October 2020, the BC Environmental Assessment Certificate was extended for another five years.

FortisBC Energy's proposed pipeline expansion remains contingent on Woodfibre LNG Limited making a final decision to proceed with construction of the LNG facility. At this time, should the project proceed, the earliest construction start date expected is late-2021.

Transmission Integrity Management Capabilities Project
This project improves gas line safety and transmission system integrity, including gas line modifications and looping. A CPCN application is expected to be filed with the BCUC in the first quarter of 2021.

Inland Gas Upgrades Project
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
Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. The project received an Order in Council from the Government of British Columbia in 2017. In February 2020 an initial project scope was filed with regulators to begin the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2021.

Tilbury LNG Resiliency Tank
This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. In December 2020 FortisBC Energy filed a CPCN application for this project with the BCUC.

AMI Project
Replacement of residential and small commercial meters and installation of bypass valves to avoid future interruption of gas service. The project will assist in load management by allowing remote meter reading on a near real-time basis and remote shutoff of gas flow. FortisBC Energy plans to file a CPCN application for this project with the BCUC in the first half of 2021.

Wataynikaneyap Transmission Power Project
Construction of a 1,800 kilometre, Ontario Energy Board regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid, in which Fortis holds a 39% equity interest. FortisOntario is responsible for construction management and operation of the transmission line. The project is on track with completion expected in 2023.

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

ITC - Lake Erie Connector
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 permits have been approved. 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 four years from the commencement of construction.

FortisBC Energy - LNG
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. FortisBC Energy 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; further gas infrastructure opportunities at FortisBC Energy; and cleaner energy infrastructure investments across our jurisdictions.

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 of directors and any material risks identified are communicated to Fortis management and form part of Fortis' ERM program. The Fortis board of directors, 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, 2020. 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, ROE adders for independent transmission ownership and deemed capital structure as well as operating and capital expenditures. These challenges could have a Material Adverse Effect.

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 the 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 30), 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 to operating facilities over time. 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, the occurrence of significant unforeseen equipment failures, 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.

Pandemics and Public Health Crises, including the COVID-19 Pandemic

The Corporation could be negatively impacted by a widespread outbreak of communicable diseases or other public health crises that cause economic and/or other disruptions. The COVID-19 Pandemic continues to be an evolving situation that has adversely impacted economic activity and conditions around the world, including the Corporation's service territories (see "General Economic Conditions" and "Access to Capital" on page 34). The virus and efforts to reduce the health impacts and control its spread have led many jurisdictions around the world, including Canada, the US and the Caribbean, to institute restrictions on travel, gatherings and business operations. The Corporation and its utilities have been subjected to government and regulatory action in response to the COVID-19 Pandemic, including restrictions on business operations, customer deferrals and suspension of disconnections. Other potential impacts on the Corporation's operations may include reduced labour availability and

productivity, disruptions to capital markets leading to share price volatility and liquidity issues, supply chain disruptions, project construction delays and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill.

The overall impact will depend on the duration and severity of the pandemic, potential government actions to mitigate public health effects or aid economic recovery, and other factors beyond the Corporation's control. An extended period of economic disruption could have a Material Adverse Effect.

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 leaks and other accidents involving gas systems. The key environmental risks for hydroelectric generation operations include dam failures and the creation of artificial water flows that may disrupt natural habitats.

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, 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.

Growth

Fortis has a history of growth through acquisitions and organic growth from capital investment 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 24. 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 cost 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.

Weather Variability and Seasonality
Electricity consumption varies significantly in response to climate change and seasonal weather changes (see "Climate Change and Physical Risks" on page 28). 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.

Natural Gas Competitiveness
Approximately 19% of the Corporation's revenue is derived from the delivery of 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 80% 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, 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 tax on carbon-based fuels which is expected to increase in the future. However, the Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. As all levels of government become more active in the development of policies to address climate change, any resultant 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.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source, and type of housing stock being built. In addition, as part of their own climate change policy plans, local governments may use various tools at their disposal such as franchise agreements, permits, building codes and zoning bylaws to impose limitations on energy sources permitted in new and existing developments. The municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free options for their developments. These actions and policies may hinder the Corporation's ability to attract new customers or retain existing customers.

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 10); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 39).

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 sales growth. These 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.

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, Indigenous Peoples and/or third parties. The external environment has become more complex with heightened expectations from permitting agencies, local municipalities and Indigenous Peoples to be able to review and provide feedback on projects, largely driven by policy responses to climate change. There is no assurance that: (i) all of these approvals 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.

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.

Indigenous Peoples' Land Claims
In British Columbia, the Corporation's utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. Various treaty negotiation processes involving Indigenous Peoples and the Governments of British Columbia and Canada are underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in the processes. 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 processes will not have a Material Adverse Effect.

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by TransAta 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.

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. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

Wataynikaneyap Partnership, which is owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), is 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.

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 MISO 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.

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: (i) support the operation of electric generation, transmission and distribution facilities, including gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations.

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.

Interest Rates
Generally, 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.

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. The nature, timing or impact of changes in future tax laws cannot be predicted and 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.

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 flow 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, 2020, US$2.3 billion (2019 - US$2.2 billion) of corporately issued US dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$10.2 billion (2019 - US$9.7 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 flow 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=CA$1.34 as at December 31, 2020 would increase or decrease annual EPS by approximately six cents, which reflects the Corporation's hedging program.

The Corporation's $19.6 billion five-year capital plan for 2021 through 2025 also includes exposure to foreign exchange. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar would increase or decrease capital expenditures by $400 million over the five-year planning period.

There is no assurance that existing hedging strategies will continue to be effective and the resultant financial impacts could have a Material Adverse Effect.

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 Flow 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 19.

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.

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 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. Significant failures in attracting or retaining a skilled workforce 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.

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 requirements could have a Material Adverse Effect.

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, including making it more difficult for customers to pay their bills.

Reputation, Relationships and Stakeholder Activism
The Corporation’s operations and growth prospects require strong relationships with key stakeholders, including regulators, 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.

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

Financial Instruments
Effective January 1, 2020, the Corporation adopted ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimation of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The new guidance also requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. Adoption did not have a material impact on the 2020 Annual Financial Statements and related disclosures. Further information is provided in Note 3 in the 2020 Annual Financial Statements.

Critical Accounting Estimates

General
The preparation of the 2020 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, 2020, Fortis recognized regulatory assets of $3.6 billion (2019 - $3.4 billion) and regulatory liabilities of $3.1 billion (2019 - $3.4 billion).

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) obligations 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. There is no assurance that actual settlement amounts and the related settlement periods will not be materially different from those estimated. 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	**2020**	2019	**2020**	2019
Funded status: [1] *($ millions)*				
Benefit obligation [2]	**(3,995)**	(3,632)	**(789)**	(712)
Plan assets	**3,528**	3,208	**391**	343
	(467)	(424)	**(398)**	(369)
Net benefit cost [2] *($ millions)*	**67**	65	**32**	28
Key assumptions: *(weighted average %)*				
Discount rate: [3]				
During the year	**3.16**	4.05	**3.22**	4.10
As at December 31	**2.63**	3.20	**2.64**	3.25
Expected long-term rate of return on plan assets [4]	**5.52**	5.78	**5.28**	5.50
Rate of compensation increase	**3.34**	3.33	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.61**	4.62

(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 2021 rate is 5.91% and is assumed to decrease over the next 11 years to the ultimate rate of 4.61% in 2031 and thereafter.*

Sensitivity Analysis Year ended December 31, 2020 *($ millions)*	Rate of Return - 1% change		Discount Rate - 1% change		Health Care Costs Trend Rate - 1% change	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Defined benefit pension plans:						
Net benefit cost	(30)	25	(45)	63	n/a	n/a
Projected benefit obligation	44	(82)	(541)	691	n/a	n/a
OPEB plans:						
Net benefit cost	(4)	4	(9)	13	29	(21)
Accumulated benefit obligation	—	—	(113)	144	106	(84)

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, 2020, Fortis recognized property, plant and equipment and intangible assets of $37.3 billion (2019 - $35.2 billion) representing 67% of total assets (2019 - 66%). Depreciation and amortization totalled $1.4 billion for 2020 (2019 - $1.4 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, 2020, this regulatory liability was $1.2 billion (2019 - $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, 2020, Fortis recognized goodwill of $11.8 billion (2019 - $12.0 billion), representing 21% of total assets (2019 - 22%). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill.

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 on each reporting unit 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. When a quantitative assessment is necessary, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. 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.

Although the macro-economic impact of the COVID-19 Pandemic is pervasive throughout each reporting unit's service territory, it is expected to be short term in nature and therefore not expected to have a material impact on long-term sustaining cash flows. No goodwill impairment was recognized in 2020 or 2019, pursuant to the annual assessments.

Income Tax
As at December 31, 2020, 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 $3.3 billion, $72 million, $1.7 billion and $1.4 billion, respectively (2019 - $3.0 billion, $35 million, $1.6 billion and $1.4 billion, respectively). Income tax expense was $231 million in 2020 (2019 - $289 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. A valuation allowance is recognized in earnings to the extent that future tax recovery is not assessed as "more likely than not".

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 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 28 in the 2020 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, 2020, the carrying value of long-term debt, including the current portion, was $24.5 billion (2019 - $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 - $25.3 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

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are 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 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, 2020, unrealized losses of $73 million (2019 - $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 - $2 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 incorporating, where possible, independent third-party information.

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 or losses associated with changes in the fair value of these energy contracts are recognized in revenue and were not material for 2020 and 2019.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $113 million and terms of one to three years expiring at varying dates through January 2023. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net and were not material for 2020 and 2019.

Foreign exchange contracts
The Corporation holds US dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through February 2022 and have a combined notional amount of $245 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net and were not material for 2020 and 2019.

Interest rate swaps
ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of $611 million, were terminated in May 2020 with the issuance of US$700 million senior notes. Realized losses of $31 million were recognized in other comprehensive income and are being reclassified to earnings as a component of interest expense over five years.

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 are recognized in other income, net and were not material for 2020 and 2019.

Derivative Fair Values
The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1** [1]	**Level 2** [1]	**Level 3** [1]	**Total**
As at December 31, 2020				
Assets [2]				
Energy contracts subject to regulatory deferral	**—**	**38**	**—**	**38**
Energy contracts not subject to regulatory deferral	**—**	**6**	**—**	**6**
Foreign exchange contracts and total return swaps	**16**	**—**	**—**	**16**
Other investments	**126**	**—**	**—**	**126**
	142	**44**	**—**	**186**
Liabilities [3]				
Energy contracts subject to regulatory deferral	**—**	**(94)**	**—**	**(94)**
Energy contracts not subject to regulatory deferral	**—**	**(12)**	**—**	**(12)**
	—	**(106)**	**—**	**(106)**
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)

[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 fair value measurement.*
[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

As at December 31	2020	2019
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**522**	628
Electricity power purchase contracts *(GWh)*	**2,781**	3,198
Gas swap contracts *(PJ)*	**156**	168
Gas supply contract premiums *(PJ)*	**203**	241
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,588**	1,855
Gas swap contracts *(PJ)*	**36**	43

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

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2020	2019	2018
Revenue	**8,935**	8,783	8,390
Net earnings	**1,389**	1,852	1,286
Common Equity Earnings	**1,209**	1,655	1,100
EPS: *($)*			
Basic	**2.60**	3.79	2.59
Diluted	**2.60**	3.78	2.59
Total assets	**55,481**	53,404	53,051
Long-term debt (excluding current portion)	**23,113**	21,501	23,159
Dividends declared: *($)*			
Per common share	**1.965**	1.855	1.750
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G [1]	**1.0983**	1.0983	1.0345
Series H [2]	**0.5003**	0.6250	0.6250
Series I [3]	**0.4987**	0.7771	0.7116
Series J	**1.1875**	1.1875	1.1875
Series K [4]	**0.9823**	0.9823	1.0000
Series M [5]	**0.9783**	1.0133	1.0250

(1) *The annual dividend per share was reset to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.*
(2) *The annual dividend per share was reset to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*
(3) *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.*
(4) *The annual dividend per share was reset to $0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.*
(5) *The annual dividend per share was reset to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

2020/2019
For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 5, "Operating Results" on page 9, and "Financial Position" on page 18.

2019/2018

The increase in revenue reflected: (i) Rate Base growth, led by ITC; (ii) overall higher flow-through costs in customer rates; (iii) favourable foreign exchange; and (iv) a $91 million favourable adjustment associated with the November 2019 FERC decision at ITC. 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.

The increase in Common Equity Earnings reflected the following significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion; and (ii) an $83 million favourable adjustment resulting from the November 2019 FERC decision at ITC, discussed above.

Excluding the significant one-time items, the increase in Common Equity Earnings was primarily due to Rate Base growth; lower operating expenses, primarily at FortisAlberta; and favourable foreign exchange. The increase was partially offset by the impact of weather in Belize and Arizona, higher costs associated with Rate Base growth not reflected in customer rates at UNS Energy, regulatory decisions at ITC, and lower realized margins at Aitken Creek. One-time positive tax adjustments, primarily recognized in 2018, also contributed to the increase in earnings, as discussed below.

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.

The increase in EPS reflects the above-noted earnings increases, partially offset by 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; (ii) ATM Program; and (iii) DRIP and share purchase plan.

The increase in total assets was due to 2019 capital expenditures, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales	**2020**	2019	Variance
Regulated utilities			
UNS Energy			
Retail Electricity *(GWh)*	**2,345**	2,223	122
Wholesale Electricity *(GWh)*	**1,871**	1,814	57
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity *(GWh)*	**1,200**	1,188	12
Gas *(PJ)*	**7**	6	1
FortisBC Energy *(PJ)*	**67**	71	(4)
FortisAlberta *(GWh)*	**4,138**	4,279	(141)
FortisBC Electric *(GWh)*	**894**	888	6
Other Electric *(GWh)*	**2,362**	2,427	(65)
Non-regulated			
Energy Infrastructure *(GWh)*	**103**	14	89

The increase in electricity sales was driven by: (i) higher retail electricity sales at UNS Energy due to favourable weather; and (ii) increased hydroelectric production in Belize due to higher rainfall levels. The increase was tempered by lower average consumption by oil and gas and commercial customers at FortisAlberta, largely associated with the COVID-19 Pandemic and the downturn in the oil and gas sector.

Gas volumes were slightly lower than 2019 due to lower consumption by transportation customers at FortisBC Energy.

Revenue and Common Equity Earnings	Revenue			Earnings		
($ millions, except as indicated)	**2020**	2019	Variance	**2020**	2019	Variance
Regulated utilities						
ITC	**419**	500	(81)	**109**	171	(62)
UNS Energy	**525**	510	15	**45**	38	7
Central Hudson	**242**	226	16	**35**	30	5
FortisBC Energy	**476**	428	48	**74**	77	(3)
FortisAlberta	**139**	150	(11)	**33**	33	—
FortisBC Electric	**117**	112	5	**13**	12	1
Other Electric	**381**	381	—	**32**	22	10
Non-regulated						
Energy Infrastructure	**47**	19	28	**27**	6	21
Corporate and Other	**—**	—	—	**(37)**	(43)	6
Total	**2,346**	2,326	20	**331**	346	(15)
Weighted average number of common shares outstanding *(millions)*				**465.8**	447.1	18.7
Basic EPS *($)*				**0.71**	0.77	(0.06)

The increase in revenue was driven by: (i) overall higher flow-through costs, mainly at FortisBC Energy; (ii) Rate Base growth; and (iii) the impact of favourable weather including higher retail sales in Arizona and hydroelectric production in Belize. The increase was partially offset by the $91 million favourable ROE adjustment recorded in the fourth quarter of 2019 by ITC associated with the November 2019 FERC decision (see "Regulatory Highlights" on page 15).

The decrease in Common Equity Earnings was due primarily to the implementation of the November 2019 FERC decision in the fourth quarter of 2019 including the reversal of prior period liabilities. This impact was partially offset by Rate Base growth, the favourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek, and higher hydroelectric production in Belize.

The decrease in basic EPS reflects lower Common Equity Earnings and an increase in the weighted average number of common shares outstanding associated with the Corporation's December 2019 common equity offering.

Cash Flows			
($ millions)	**2020**	2019	Variance
Cash, beginning of period	**494**	228	266
Cash from (used in):			
Operating activities	**700**	634	66
Investing activities	**(1,235)**	(1,104)	(131)
Financing activities	**308**	627	(319)
Foreign exchange	**(18)**	(15)	(3)
Cash, end of period	**249**	370	(121)

Operating Activities
The variance largely reflects the upfront payment received by FortisAlberta in the fourth quarter of 2020 associated with a long-term energy retailer agreement. An increase in Operating Cash Flow associated with higher energy sales was largely offset by the timing of the recovery of flow-through costs and slower collections from customers associated with the COVID-19 Pandemic.

Investing Activities
The variance reflects higher capital expenditures in accordance with the Corporation's capital plan.

Financing Activities
See "Cash Flow Summary" on page 20.

SUMMARY OF QUARTERLY RESULTS

Quarter Ended	Revenue ($ millions)	Common Equity Earnings ($ millions)	Basic EPS ($)	Diluted EPS ($)
December 31, 2020	**2,346**	**331**	**0.71**	**0.71**
September 30, 2020	**2,121**	**292**	**0.63**	**0.63**
June 30, 2020	**2,077**	**274**	**0.59**	**0.59**
March 31, 2020	**2,391**	**312**	**0.67**	**0.67**
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

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) any 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 2020/December 2019
See "Fourth Quarter Results" on page 42.

September 2020/September 2019
Common Equity Earnings increased by $14 million due mainly to: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates; and (ii) lower contributions from ITC, due to the timing of earnings associated with the FERC ROE decisions, and a lower effective tax rate in 2019. The $0.01 decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019, partially offset by the above noted factors.

June 2020/June 2019
Common Equity Earnings decreased by $446 million and basic EPS decreased by $1.07. Earnings for the quarter reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the reversal of a $13 million tax recovery, originally recognized in 2019, due to the finalization in April 2020 of anti-hybrid regulations associated with US tax reform, partially offset by; (iii) a $27 million favourable base ROE adjustment at ITC as a result of the May 2020 FERC decision reflecting the reversal of liabilities accrued in prior years. Notwithstanding the significant one-time items, the regulated utilities delivered improved financial results reflecting: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; (iii) favourable foreign exchange; and (iv) timing of operating expenses at FortisBC Energy. This growth was tempered by lower sales in the Caribbean due to a decline in tourism-related activities and higher COVID-related expenses, driven by Central Hudson.

March 2020/March 2019
Common Equity Earnings were comparable with 2019. Rate Base growth, lower non-recoverable operating expenses at ITC, and lower expenses in the Corporate and Other segment were tempered by: (i) higher costs associated with Rate Base growth at UNS Energy not yet reflected in rates; (ii) financial market volatility that caused a decline in the market value of certain investments that support retirement benefits at UNS Energy; and (iii) unrealized losses on foreign exchange contracts in the Corporate and Other segment. The decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

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 2020 or 2019. Inter-company balances, transactions and profit between non-regulated and regulated entities are not eliminated on consolidation. 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.

As at December 31, 2020, accounts receivable included approximately $28 million due from Belize Electricity (2019 - $8 million).

Fortis periodically provides short-term financing to its subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2020, there were no material inter-segment loans outstanding (2019 - $279 million). The interest charged on inter-segment loans in 2020 and 2019 was not material.

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, 2020, 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 US securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2020.

Internal Controls 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, 2020, 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, 2020, the Corporation's ICFR was effective.

During the year ended December 31, 2020, 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

The Corporation maintains its positive long-term outlook. Fortis continues 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. While uncertainty exists due to the COVID-19 Pandemic, the Corporation does not currently expect it to have a material financial impact in 2021.

The Corporation's $19.6 billion five-year capital plan is expected to increase Rate Base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, translating into three- and five-year CAGRs of approximately 6.5% and 6.0%, respectively. Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: 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 infrastructure investments across our jurisdictions.

Fortis expects long-term growth in Rate Base will support earnings and dividend growth. Fortis is targeting average annual dividend growth of approximately 6% through 2025. This dividend growth guidance is premised on the assumptions listed under "Forward-Looking Information" below, including no material impact from the COVID-19 Pandemic, the expectation of reasonable outcomes for regulatory proceedings, and the successful execution of the five-year capital plan.

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: the expectation that the COVID-19 Pandemic will not have a material financial impact in 2021 and will not impact the five-year capital plan; targeted average annual dividend growth through 2025; forecast capital expenditures for 2021-2025 and expected funding sources; forecast Rate Base and Rate Base growth for 2023 and 2025; the expectation that long-term growth in Rate Base will support earnings and dividend growth; the expectation that Fortis will remain at the forefront of the industry and is well positioned to capitalize on evolving industry opportunities; expected timing, outcome and impact of regulatory 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 in 2021; the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Oso Grande Wind Project, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Resiliency Tank, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan, including the Lake Erie Connector Project; and the expectation that the adoption of future accounting pronouncements will not have a Material Adverse Impact.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information including, without limitation: no material impact from the COVID-19 Pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the five-year capital plan; no material capital project or financing cost overrun; 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.

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 2021 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change, physical risks and service disruption; the impact of pandemics and public health crises, including the COVID-19 Pandemic; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; and the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation.

All forward-looking information herein is given as of February 11, 2021. 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

2020 Annual Financial Statements: *the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2020*

ACC: *Arizona Corporation Commission*

ACCP: *AESO customer contribution policy*

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 15*

Adjusted Payout Ratio: *dividends per common share divided by Adjusted Basic EPS as shown under "Non-US GAAP Financial Measures" on page 15*

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.*

AMI**:** *Advanced Metering Infrastructure*

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. Calculated on a constant US dollar to Canadian dollar exchange rate*

Caribbean Utilities: *Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2020) 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*

COVID-19 Pandemic: declared by the World Health Organization in March 2020 as a result of a novel coronavirus

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*

Four Corners: *Four Corners Generating Station, Units 4 and 5*

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

GCOC: *generic cost of capital*

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*

LIBOR: *London Interbank Offered Rate*

LNG: *liquefied natural gas*

Luna: *Luna Energy Facility*

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, 2020*

MISO: *Midcontinent Independent System Operator, Inc.*

MRP: *Multi-Year Rate Plan*

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

MW: *megawatt(s)*

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

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

NOPR*: notice of proposed rulemaking*

NYSE: *New York Stock Exchange*

OEB: *Ontario Energy Board*

OPEB: *other post-employment benefits*

Operating Cash Flow: *cash from operating activities*

PBR: *performance-based rate-setting*

PJ: *petajoule(s)*

PPA: *power purchase agreement*

PSC*: New York State Public Service Commission*

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*

RICE Units: *natural gas reciprocating internal combustion engine units*

ROA: *rate of return on Rate Base*

ROE: *rate of return on common equity*

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

San Juan: *San Juan Generating Station Unit 1*

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

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

TFO*: transmission facility owners*

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*

Exhibit 99.4

Rule 13a-14(a) or Rule 15d-14(a) Certification - Chief Executive Officer

I, David G. Hutchens, certify that:

1. I have reviewed this annual report on Form 40-F of Fortis Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ David G. Hutchens
David G. Hutchens
President and Chief Executive Officer

St. John's, Canada
February 12, 2021

Exhibit 99.5

Rule 13a-14(a) or Rule 15d-14(a) Certification - Chief Financial Officer

I, Jocelyn H. Perry, certify that:

1. I have reviewed this annual report on Form 40-F of Fortis Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ Jocelyn H. Perry
Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

St. John's, Canada
February 12, 2021

Exhibit 99.6

Rule 13a-14(b) Certification Chief Executive Officer

In connection with the annual report of Fortis Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David G. Hutchens, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David G. Hutchens
David G. Hutchens
President and Chief Executive Officer

St. John's, Canada
February 12, 2021

Exhibit 99.7

Rule 13a-14(b) Certification Chief Financial Officer

In connection with the annual report of Fortis Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jocelyn H. Perry, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Jocelyn H. Perry
Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

St. John's, Canada
February 12, 2021

Exhibit 99.8

Consent of Report of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement Nos. 333-215777, 333-226663 and 333-236213 on Form S-8, 333-250996 on Form F-10, and 333-249039 on Form F-3 and to the use of our reports dated February 11, 2021 relating to the consolidated financial statements of Fortis Inc. and the effectiveness of Fortis Inc.'s internal control over financial reporting appearing in this Annual Report on Form 40-F for the year ended December 31, 2020.

/s/ Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 12, 2021