St. John's, NL - February 10, 2023

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2022 RESULTS

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2022 fourth quarter and annual financial results[1].

Highlights

- Reported net earnings of $1.3 billion, or $2.78 per common share in 2022
- Adjusted net earnings per common share[2] of $2.78, up from $2.59 in 2021, representing ~7% annual EPS growth
- Capital expenditures[2] of $4.0 billion, with over $600 million focused on delivering cleaner energy, yielding ~7% rate base growth[3]
- Scope 1 emissions 28% below 2019 levels; 75% emissions reduction by 2035 target on track in support of 2050 net-zero goal
- Capital structure complaint filed against ITC Midwest denied by FERC

"2022 was a year of execution with strong financial, operational and sustainability results across our utilities," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "We invested over $4 billion in capital, delivered strong EPS and rate base growth, and further reduced our carbon emissions. We also outperformed safety and reliability industry averages and were recognized as a leader in Canada for our governance practices."

"With a focus on organic growth, we also announced our largest five-year capital plan of $22.3 billion representing steady rate base growth of 6% and supporting annual dividend growth guidance of 4-6% through 2027," said Mr. Hutchens. "We appreciate the dedication and hard work of our people to make 2022 another successful year."

Net Earnings

The Corporation reported net earnings attributable to common equity shareholders ("Net Earnings") for 2022 of $1.3 billion, or $2.78 per common share, compared to $1.2 billion, or $2.61 per common share for 2021. The increase was primarily driven by rate base growth across our utilities. The increase was also due to higher electricity sales and transmission revenue in Arizona, and higher earnings at Aitken Creek. The translation of U.S. dollar-denominated subsidiary earnings at a higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results.

Growth in earnings was tempered by certain discrete items at ITC, including costs associated with the suspension of the Lake Erie Connector project, the revaluation of deferred income tax assets, and an adjustment in 2021 related to interest rate swaps. Losses on investments that support retirement benefits at UNS Energy and ITC, higher operating costs at Central Hudson related to the implementation of a new customer information system, and higher corporate costs also impacted results. In addition, net earnings per common share reflected an increase in the weighted average number of common shares outstanding largely associated with the Corporation's dividend reinvestment plan.

For the fourth quarter of 2022, Net Earnings were $370 million, or $0.77 per common share, compared to $328 million or $0.69 per common share for the same period in 2021. The increase was due to rate base growth, higher retail electricity sales and transmission revenue at UNS Energy, higher hydroelectric production in Belize, and the timing of expenses at FortisAlberta. The higher foreign exchange rate and lower stock based compensation costs, as discussed above, also favourably impacted results. The increase was partially offset by higher corporate costs as well as lower earnings at Central Hudson due to the timing of approval of its rate application in 2021, and for net earnings per common share, an increase in the weighted average number of common shares.

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

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

[3] Calculated using a constant United States dollar-to-Canadian dollar exchange rate.

Adjusted Net Earnings[2]

Adjusted net earnings attributable to common equity shareholders ("Adjusted Net Earnings") excludes non-recurring items and the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek. Adjusted Net Earnings of $1.3 billion for 2022, or $2.78 per common share, were $110 million, or $0.19 per common share higher than 2021. For the fourth quarter of 2022, Adjusted Net Earnings were $347 million, or $0.72 per common share, an increase of $47 million, or $0.09 per common share compared to the same period in 2021. The increase in adjusted earnings for the fourth quarter and the year was driven by the same factors discussed for Net Earnings.

Capital Expenditures[2]

Capital expenditures were $4.0 billion, consistent with the 2022 capital plan, and mainly consisted of regulated investments focused on system resiliency, grid modernization and sustainable energy, including more than $600 million in cleaner energy investments. Capital expenditures increased midyear rate base to $34.1 billion, representing 7% growth over 2021[3].

The Corporation's five-year capital plan for 2023 through 2027 is $22.3 billion, the largest in the Corporation's history. In total, Fortis expects to invest $5.9 billion in cleaner energy over the next five years. These investments will focus on connecting renewables to the grid, including Tranche 1 of the Midcontinent Independent System Operator ("MISO") long-range transmission plan ("LRTP"), renewable and storage investments in Arizona and the Caribbean, and cleaner fuel solutions in British Columbia. The plan incorporates key customer affordability considerations, recognizing the impacts of inflation and elevated commodity costs on customer rates, while ensuring reliable and resilient energy delivery service as we transition to a cleaner energy future.

The five-year capital plan is expected to be funded primarily by cash from operations, debt issued at the regulated utilities and common equity from the Corporation's dividend reinvestment plan.

Non-U.S. GAAP Reconciliation

Periods ended December 31	Quarter			Annual		
($ millions, except earnings per share)	**2022**	2021	Variance	**2022**	2021	Variance
Adjusted Net Earnings						
Net Earnings	**370**	328	42	**1,330**	1,231	99
Adjusting items:						
Unrealized gain on mark-to-market of derivatives[4]	**(23)**	(28)	5	**(20)**	(12)	(8)
Lake Erie Connector project suspension costs[5]	**—**	—	—	**10**	—	10
Revaluation of deferred income tax assets[6]	**—**	—	—	**9**	—	9
Adjusted Net Earnings	**347**	300	47	**1,329**	1,219	110
Adjusted Basic EPS *($)*	**0.72**	0.63	0.09	**2.78**	2.59	0.19
Capital Expenditures						
Additions to property, plant and equipment	**987**	897	90	**3,587**	3,189	398
Additions to intangible assets	**127**	77	50	**278**	197	81
Adjusting item:						
Wataynikaneyap Transmission Power Project[7]	**34**	35	(1)	**169**	178	(9)
Capital Expenditures	**1,148**	1,009	139	**4,034**	3,564	470

4 Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $8 million and $7 million for the three and twelve months ended December 31, 2022, respectively ($11 million and $5 million for the three and twelve months ended December 31, 2021, respectively).

5 Represents costs incurred upon the suspension of the Lake Erie Connector project, net of income tax recovery of $nil and $4 million for the three and twelve months ended December 31, 2022, respectively.

6 Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa.

7 Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project.

Regulatory Updates

In November 2022, FERC issued an order denying the complaint filed by the Iowa Coalition for Affordable Transmission ("ICAT"), which sought to lower ITC Midwest's equity ratio from 60% to 53%. FERC concluded that ICAT had not demonstrated that ITC Midwest failed to meet the three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In December 2022, ICAT filed a request for rehearing with FERC. The Corporation continues to believe the complaint is without merit.

Focus on Sustainability

Fortis achieved a 28% reduction in Scope 1 emissions through 2022 compared to 2019 levels, equivalent to taking approximately 760,000 vehicles off the road in one year. The closure of the 170-megawatt coal-fired San Juan Generating Station in Arizona in mid-2022 contributed to the reduction. The Corporation is more than halfway to achieving its target to reduce greenhouse gas ("GHG") emissions 50% by 2030, and remains on track to reduce GHG emissions 75% by 2035. Upon achieving these targets, 99% of the Corporation's assets will be focused on energy delivery and renewable, carbon-free generation. Additionally, in 2022, Fortis established a 2050 net-zero direct GHG emissions target, reinforcing the Corporation's commitment to long-term decarbonization, while preserving customer reliability and affordability.

During the year, Fortis released its inaugural Task Force for Climate-Related Financial Disclosures ("TCFD") and Climate Assessment Report and its 2022 Sustainability Report. The TCFD and Climate Assessment Report advanced the Corporation's commitment as a TCFD supporter and included an analysis of risks and opportunities associated with four climate-related scenarios. The 2022 Sustainability Report fully aligned with applicable Sustainability Accounting Standards Board standards and included over 35 new key performance indicators. The report also provided an update on efforts to increase renewable generation sources, including new wind and solar generation at Tucson Electric Power.

Progress continued on the Wataynikaneyap Transmission Power Project during 2022. In August 2022, Phase 1 of the project was completed, energizing the 230 kV line from Dinorwic to Pickle Lake, Ontario. At the end of 2022, the project was 73% complete, with 700 kilometers of transmission line energized and three First Nation communities connected to the Ontario electric grid. Construction is expected to be completed in 2024.

Outlook

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. While energy price volatility, global supply chain constraints and persistent inflation are issues of potential concern that continue to evolve, the Corporation does not currently expect there to be a material impact on its operations or financial results in 2023.

The Corporation's $22.3 billion five-year capital plan is expected to increase midyear rate base from $34.1 billion in 2022 to $46.1 billion by 2027, translating into a five-year compound annual growth rate of 6.2%[3].

Beyond the five-year capital plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the Inflation Reduction Act of 2022 and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and liquefied natural gas infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2027. This dividend growth guidance will also provide flexibility to fund more capital with internally-generated funds and is premised on the assumptions and material factors listed under "Forward-Looking Information".

About Fortis

Fortis is a well-diversified leader in the North American regulated electric and gas utility industry with 2022 revenue of $11 billion and total assets of $64 billion as at December 31, 2022. The Corporation's 9,200 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Forward-Looking Information

Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the 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 and 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 2023-2027, including cleaner energy investments; forecast rate base and rate base growth through 2027; targeted annual dividend growth through 2027; the expected sources of funding for the 2023-2027 capital plan; the nature, timing, benefits and expected costs of certain capital projects, including the Wataynikaneyap Transmission Power project, ITC's transmission projects associated with the MISO LRTP, renewable energy and storage investments in Arizona and the Caribbean, and investments in cleaner fuel solutions in British Columbia, and additional opportunities beyond the capital plan, including investments related to the Inflation Reduction Act of 2022, the MISO LRTP, climate adaptation and grid resiliency, and renewable gas solutions and liquefied natural gas infrastructure in British Columbia; the expected timing, outcome and impact of regulatory proceedings and decisions; the 2030 GHG emissions reduction target; the 2035 GHG emissions reduction target and projected asset mix; the 2050 net-zero direct GHG emissions target; the expectation that volatility in energy prices, global supply chain constraints and persistent inflation will not have a material impact on operations or financial results in 2023; the expectation that long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2027; and the expectation that the dividend growth guidance will provide flexibility to fund more capital internally.

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 volatility in energy prices, global supply chain constraints and persistent inflation; reasonable outcomes for regulatory proceedings and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project and financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar to Canadian dollar exchange rate; and the Board exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. For additional information with respect to certain risk factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information herein is given as of the date of this media release. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Teleconference to Discuss 2022 Annual Results

A teleconference and webcast will be held on February 10, 2023 at 8:30 a.m. (Eastern). David Hutchens, President and Chief Executive Officer and Jocelyn Perry, Executive Vice President and Chief Financial Officer, will discuss the Corporation's 2022 annual results.

Shareholders, analysts, members of the media and other interested parties in North America are invited to participate by calling 1.416.764.8658. International participants may participate by calling 1.888.886.7786. Please dial in 10 minutes prior to the start of the call. No passcode is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com. A replay of the teleconference will be available two hours after the conclusion of the call until March 10, 2023. Please call 1.416.764.8692 or 1.877.674.7070 and enter passcode 760995#.

Additional Information

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

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Management Discussion and Analysis

Contents

Dated February 9, 2023

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2022 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 42. 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.

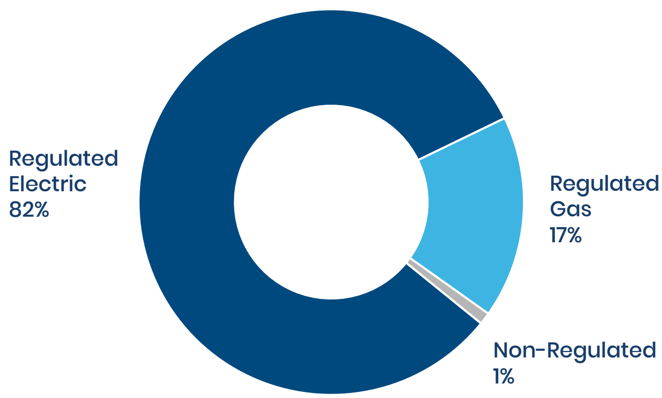
Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.30 and 1.25 for the years ended December 31, 2022 and 2021, respectively; (ii) 1.36 and 1.26 as at December 31, 2022 and 2021, respectively; (iii) average of 1.36 and 1.26 for the quarters ended December 31, 2022 and 2021, respectively; and (iv) 1.30 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 43.

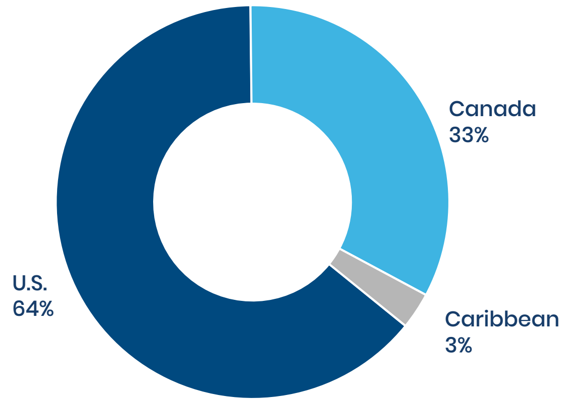
ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $11 billion in 2022 and total assets of $64 billion as at December 31, 2022.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,200 employees serve 3.4 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. As at December 31, 2022, 67% of the Corporation's assets were located outside Canada and 59% of 2022 revenue was derived from foreign operations.

TOTAL ASSETS AT DECEMBER 31, 2022





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, and assets under construction in Wisconsin); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York State); 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 Fortis Belize (three hydroelectric generation facilities - Belize) and Aitken Creek (natural gas storage facility - British Columbia).

Fortis has a unique operating model with a small corporate 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 board of directors, with most having a majority of independent board 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 while focusing on sustainability policies and practices. The Corporation has established delivering a cleaner energy future as its core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders 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 2022 Annual Financial Statements.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	2022	2021	Variance
Common Equity Earnings			
Actual	**1,330**	1,231	99
Adjusted [(1)]	**1,329**	1,219	110
Basic EPS ($)			
Actual	**2.78**	2.61	0.17
Adjusted [(1)]	**2.78**	2.59	0.19
Dividends			
Paid per common share ($)	**2.17**	2.05	0.12
Actual Payout Ratio (%)	**78.1**	78.5	(0.4)
Adjusted Payout Ratio (%) [(1)]	**78.1**	79.2	(1.1)
Weighted average number of common shares outstanding (# millions)	**478.6**	470.9	7.7
Operating Cash Flow	**3,074**	2,907	167
Capital Expenditures [(1)]	**4,034**	3,564	470

(1) *See "Non-U.S. GAAP Financial Measures" on page 14*

Earnings and EPS

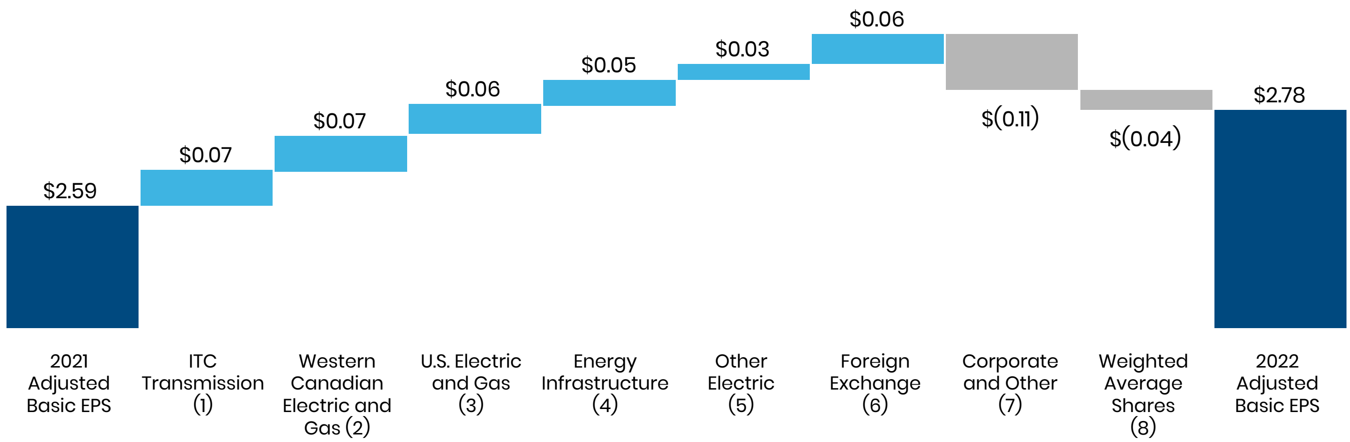
The Corporation reported Common Equity Earnings of $1.3 billion in 2022, or $2.78 per common share, compared to $1.2 billion, or $2.61 per common share in 2021. Our businesses performed well in 2022, delivering approximately 7% annual EPS growth. The increase was primarily driven by Rate Base growth across our utilities. The increase in earnings was also due to: (i) higher retail and wholesale electricity sales, as well as transmission revenue in Arizona; (ii) higher margins on gas sold and the mark-to-market accounting of natural gas derivatives at Aitken Creek; and (iii) the impact of new customer rates at Central Hudson. The translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results, with these impacts exceeding the related losses on derivatives associated with hedging activities.

Growth in earnings was tempered by certain discrete items at ITC including: (i) costs associated with the suspension of the Lake Erie Connector project; (ii) the revaluation of deferred income tax assets due to a reduction in the corporate income tax rate in the state of Iowa; and (iii) a favourable adjustment recognized in 2021 related to interest rate swaps. Losses on investments that support retirement benefits at UNS Energy and ITC, higher operating costs at Central Hudson related to the implementation of a new CIS, and higher corporate costs also tempered results.

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 DRIP.

Year over year, Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $110 million and $0.19, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 14 for a reconciliation of these measures. The changes in Adjusted Basic EPS are illustrated in the chart below.

CHANGES IN ADJUSTED BASIC EPS



(1) *Reflects Rate Base growth and lower non-recoverable stock-based compensation costs, partially offset by a favourable adjustment related to interest rate swaps in 2021, losses on investments that support retirement benefits and higher holding company finance costs*

(2) *Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, partially offset by an increase in operating expenses and a higher effective income tax rate at FortisAlberta*

(3) *Includes UNS Energy and Central Hudson. Reflects higher earnings at UNS Energy, due to higher retail and wholesale electricity sales, as well as transmission revenue, partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates, higher operating expenses, and losses on certain investments that support retirement benefits. Also reflects higher earnings at Central Hudson, driven by new customer rates due to the conclusion of the general rate application in 2021, and the impact of unfavourable regulatory deferrals recorded in 2021, partially offset by higher operating expenses associated with the implementation of a new CIS and non-recoverable finance costs*

(4) *Includes higher margins on gas sold at Aitken Creek, reflecting market conditions, and higher hydroelectric production in Belize associated with rainfall levels*

(5) *Primarily reflects Rate Base growth and higher electricity sales*

(6) *Average foreign exchange rate of 1.30 in 2022 compared to 1.25 in 2021*

(7) *Primarily reflects market conditions, including losses on total return swaps and foreign exchange contracts and higher finance costs, as well as lower income tax recovery*

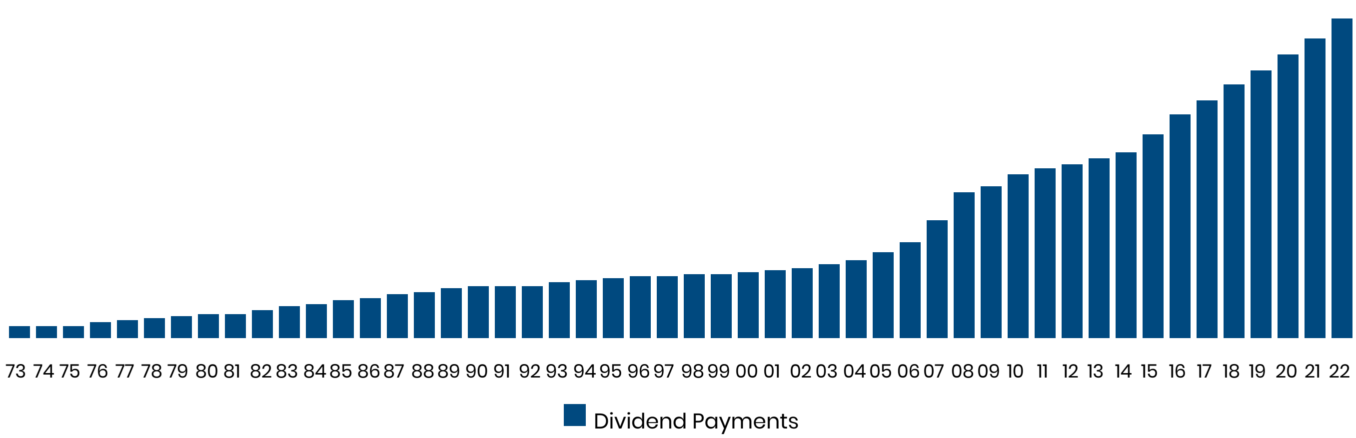
(8) *Weighted average shares of 478.6 million in 2022 compared to 470.9 million in 2021*

Dividends

Fortis paid a dividend of $0.565 per common share in the fourth quarter of 2022, up 5.6% from $0.535 paid in each of the previous four quarters. This marked the Corporation's 49^{th} consecutive year of dividend increases. The Actual Payout Ratio was 78% in 2022 and an average of 68% over the five-year period of 2018 through 2022.

Fortis is targeting annual dividend growth of approximately 4-6% through 2027. See "Outlook" on page 41.

49 YEARS OF CONSECUTIVE DIVIDEND INCREASES



Growth in dividends and changes in the market price of the Corporation's common shares have yielded the following TSR.

TSR [(1)] *(%)*	**1-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**(7.9)**	**7.2**	**8.7**	**11.3**

(1) *Annualized TSR per Bloomberg, as at December 31, 2022*

Operating Cash Flow

The $167 million increase in Operating Cash Flow was due to: (i) higher cash earnings, reflecting Rate Base growth and higher retail and long-term wholesale electricity sales, as well as transmission revenue, in Arizona; (ii) collateral deposits received at UNS Energy related to derivative energy contracts; (iii) proceeds received at ITC upon the settlement of interest rate swaps; and (iv) the higher U.S.-to-Canadian dollar exchange rate. The timing of flow-through of costs in customer rates also favourably impacted Operating Cash Flow. The increase was partially offset by higher gas inventory levels in British Columbia, as well as storm restoration costs incurred in 2022, to be recovered in future customer rates, and higher accounts receivable at Central Hudson.

Capital Expenditures

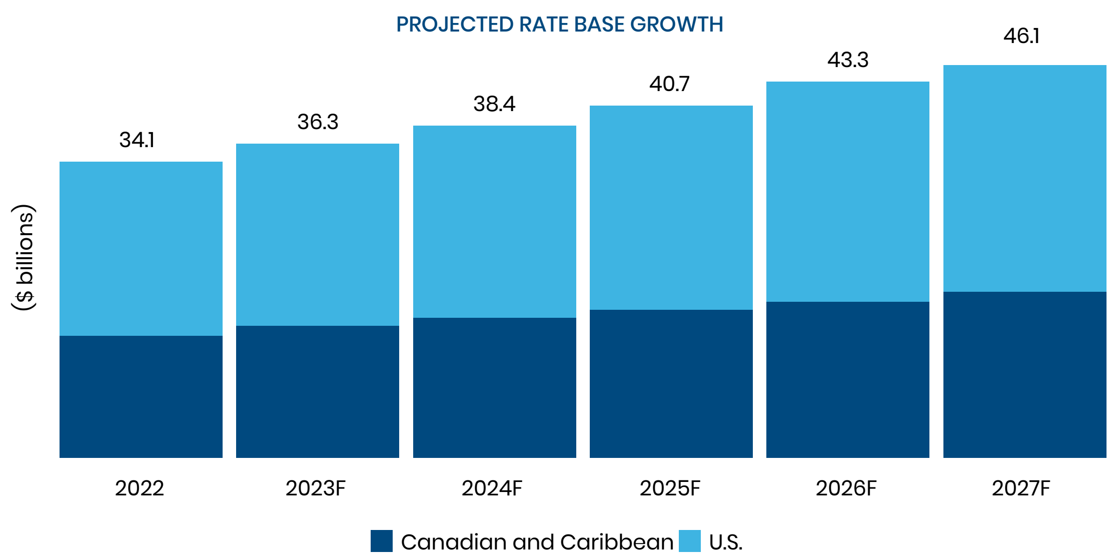
Capital Expenditures were $4.0 billion, consistent with the 2022 Capital Plan and $0.5 billion higher than 2021. The increase over 2021 was primarily due to continued investment in various smaller transmission and distribution projects at the Corporation's regulated utilities, as well as the impact of the higher average foreign exchange rate.

The Corporation's 2023-2027 Capital Plan of $22.3 billion is the largest in the Corporation's history and is $2.3 billion higher than the previous five-year plan. The increase is driven by organic growth, largely reflecting regional transmission projects associated with the MISO LRTP at ITC, additional cleaner energy investments in Arizona to support TEP's planned exit from coal by 2032, and enhancements to distribution infrastructure reliability and capacity, as well as investments to support customer growth, across the Corporation's regulated utilities. Approximately $500 million of the increase is driven by a higher assumed U.S.-to-Canadian dollar exchange rate over the five-year period. See "Capital Plan" on page 21 for further information.

Funding of the Capital Plan is expected to be primarily through Operating Cash Flow, debt issued at the regulated utilities and common equity from the Corporation's DRIP.

The five-year Capital Plan is expected to increase midyear Rate Base from $34.1 billion in 2022 to $46.1 billion by 2027, representing a five-year CAGR of 6.2%.

Capital Expenditures and Capital Plan reflect Non-U.S. GAAP financial measures. Refer to "Non-U.S. GAAP Financial Measures" on page 14 and "Capital Plan" on page 21.



Beyond the five-year Capital Plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the IRA and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American energy industry's transformation is accelerating rapidly, driven by the impacts of climate change, as well as the need for a cleaner energy future and innovation. There is a growing need for the development of cleaner energy sources and the deployment of energy conservation measures to preserve the planet for future generations. The goal of carbon emissions reduction, and associated advancements in technology, have attracted interest from investors and customers. Electric transmission is seen as a critical enabler of large-scale renewable generation. Natural gas also continues to be an important part of the energy mix, as supplemental generation to the intermittent nature of renewables, and as a cost-effective heating source. Longer term, advancements in the use of hydrogen and RNG will further 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 reflect the rising focus on climate change, with clean energy and carbon reduction goals and initiatives at the forefront. In the U.S., the IRA has been passed into law and includes, among other items, incentives and clean energy tax credits encouraging investments in clean energy, energy storage, electric vehicles and manufacturing, all to support a targeted 40% reduction in carbon emissions by 2030. With states and provinces also setting ambitious carbon reduction targets, the regulatory and compliance environment continues to evolve and become increasingly complex. These changes are creating opportunities to expand investment in new, renewable generation sources, as well as transmission infrastructure to connect renewable energy sources to the grid. In addition to growth of renewable generation, investment opportunities in energy storage technology are also being created. The electrification of the transportation sector is gaining momentum and represents a significant opportunity to reduce carbon emissions while increasing the output and efficiency of the grid. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities which will drive significant investment.

New technology is stimulating change across all of the Corporation's service territories. Energy delivery systems are becoming more intelligent, with upgraded advanced meters, additional grid automation, high-speed private communications networks, and more capable operational technology, providing utilities with detailed usage data and predictive maintenance information to improve cost efficiency and safety. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have options to manage energy usage and access to more affordable distributed generation. Grid resilience is growing in importance with the increasing frequency and intensity of weather events such as hurricanes, wildfires, floods and storms. With electricity expected to represent a larger portion of society's energy mix, investments in grid hardening and resiliency are necessary to improve the grid's ability to withstand and recover from these climate events.

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 need, and the choice and control they increasingly seek. Fortis is a 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. The Corporation is also involved in the Low Carbon Resources Initiative, a collaboration between EPRI and GTI Energy, along with major North American utilities, to develop and demonstrate the low- and zero-carbon energy technologies needed to enable pathways to economy-wide decarbonization. In 2022, Fortis also joined EPRI's Climate READi, an initiative involving major North American utilities, regulators, policy makers, and other stakeholders focused on developing an industry-wide best practice framework for managing physical climate risk.

Meaningful customer engagement is important for utilities as customer expectations change. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized self-service offerings and more real-time, digital communication. Fortis' utilities are enhancing customer information systems and digital technologies to improve customer service.

On the security front, with the advent of new and increasing cyber threats to our information and operational technology systems, increased focus and investment on protection and response to these cyber events is an ongoing priority. Upgrades to the physical security environment is also required to keep pace with evolving challenges. All these technological advancements and challenges offer strategic investment opportunities for improving and expanding customer service and enhancing security.

The Corporation's culture and decentralized structure support the efforts required to meet changing customer expectations. Each of our utilities work constructively with regulators and all stakeholders on policy, energy and service solutions, and are an integral partner in all the communities they serve. Fortis is committed to be an industry leader in the clean energy transition.

FOCUS ON SUSTAINABILITY

Fortis is dedicated to operating in an environmentally and socially responsible manner in the interests of all of its stakeholders. Fortis believes that focusing on the responsible and sustainable management of its businesses is good for employees, customers, communities and the planet, but also, importantly, shareholders. Oversight and accountability for sustainability are established at the most senior levels of the Corporation and its operating subsidiaries. At Fortis, the Board has overall responsibility for sustainability. However, primary oversight of the issues, policies and practices pertaining to sustainability has been delegated to the governance and sustainability committee of the Board, reflecting sustainability's important role in the Corporation's strategy and management of risk.

Key aspects of Fortis' sustainability program and practices are outlined below.

Climate Change and Environmental Matters

Fortis is primarily an energy delivery company with 93% of its assets related to transmission and distribution. The focus for Fortis is the delivery of cleaner energy to its customers and this limits the impact of the Corporation's utilities on the environment when compared to more generation-intensive businesses. Fortis has a relatively small amount of fossil-fuel generation in its portfolio and has a plan to transition to more renewable sources of energy for its customers.

The Corporation's direct GHG emissions come primarily from its generation assets, which largely consist of fossil fuel-based generation at TEP, representing 4% of the Corporation's total assets. Fortis continues to build on its low emissions profile, and in May 2022, set a 2050 net-zero direct GHG emissions target. This goal is in addition to the Corporation's interim targets to reduce GHG emissions 50% by 2030 and 75% by 2035 from a 2019 base year. Fortis expects to achieve both interim targets without the use of carbon offsets, primarily through delivering on TEP's plan to reduce carbon emissions, as well as clean energy initiatives across the Corporation's other utilities.

Consistent with our interim targets and pathway to net-zero, in June 2022, TEP retired 170-MW of coal-fired generation through the planned closure of San Juan. Fortis has made significant progress on its emissions reduction targets. Through 2022, the Corporation's Scope 1 emissions were 28% lower compared to 2019 levels, equivalent to taking approximately 760,000 vehicles off the road in one year.

Beyond 2035, most of the Corporation's Scope 1 emissions are expected to relate to natural gas generation at TEP. To reach net-zero by 2050, TEP will focus on developing and adopting new technologies, improving the efficiency of natural gas units, utilizing lower-carbon fuels and preparing its generating units for future hydrogen injection. Reliability and affordability will remain key priorities as Fortis works to meet its emissions reduction targets.

The Corporation made progress on its commitment as a TCFD supporter in March 2022, with the release of its first TCFD and Climate Assessment Report, which included an analysis of four climate-related scenarios and associated risks and opportunities. This report provides information on Fortis' strategy and actions to address climate change, physical and transition risks, and business opportunities including investments in resilient and adaptable infrastructure. In July 2022, Fortis released its 2022 Sustainability Report, highlighting progress on a number of sustainability priorities, including adding more renewable energy, reducing GHG emissions and improving diversity. The report also provided enhanced information on the Corporation's sustainability strategy, significantly expanded the scope of key performance indicators, and was fully aligned with applicable Sustainability Accounting Standards Board standards.

In 2022, over $600 million in Capital Expenditures were focused on the delivery of cleaner energy to customers. In the development of the Corporation's five-year Capital Plan, each of the utilities considered the investment required to deliver cleaner energy to customers, strengthen infrastructure, and improve network resiliency to deal with the expected impacts of climate change on utility infrastructure. Fortis' 2023-2027 Capital Plan includes cleaner energy investments of $5.9 billion, with investments focused on connecting renewables to the grid, renewable and storage investments, and cleaner fuel solutions. Additional information can be found in the "Capital Plan" section on page 21. In support of the capital program, during 2022, Fortis amended its unsecured $1.3 billion revolving term committed credit facility agreement to include the establishment of a sustainability-linked loan structure based on the Corporation's achievement of targets related to diversity on the Board and reduction of Scope 1 GHG emissions for 2022 through 2025.

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, seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources. 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.

Safety and Reliability

Fortis is an industry leader in safety and reliability, with the Corporation consistently performing above industry averages. Fortis leverages its unique operating model and utility experience to deliver safe and reliable service to its customers and the communities it serves. Senior operational executives from all Fortis utilities meet regularly to share best practices and identify opportunities for collaboration on a range of operational areas including health and safety.

All contractors are required to share our commitment to conduct work in a safe manner. Contractors must demonstrate a strong safety program with a high level of training centered around risk management. Historical safety performance is a consideration when selecting successful contractors.

Engaging with Stakeholders and Communities

Fortis' utilities work closely with their customers and communities to drive enhancements and improve the overall customer service experience. Customer satisfaction targets are established and customer service surveys are completed regularly focusing on customer satisfaction, reliability and accuracy of billing and metering, contact center services and reliability of energy supply.

Customer affordability is a key priority for Fortis. Historically, Fortis utilities have managed annual increases in controllable operating costs per customer to below inflation. In addition, our utilities work to ensure customers are aware of bill payment options, external government payment assistance programs, as well as home energy efficiency programs and rebates.

Fortis and its utilities work with a number of Indigenous groups, with the goal of developing long-term partnerships and creating economic opportunities. The Wataynikaneyap Power Transmission project is an 1,800 kilometer transmission line that will connect 17 First Nations communities to the Ontario power grid for the first time. These communities currently have inefficient and unreliable access to electricity based on diesel generation, compromising their economic and social well-being and limiting their opportunities for growth. The project is majority-owned by 24 First Nations, while Fortis has a 39% ownership interest and acts as project manager. Additional information can be found in the "Capital Plan" section on page 21.

Fortis and its utilities consistently look for opportunities for growth, innovation and energy efficiency in the communities they serve. Regular community engagement includes donations to local charities, partnerships with educational institutions, and participation on local boards, which enables Fortis and its utilities to serve as meaningful contributors to their local communities. In 2022, the Fortis group of companies contributed $9.7 million to the communities they serve.

Cybersecurity

Fortis' CRMP aims to continually improve information sharing and the culture of security. Fortis has an enterprise-wide CRMP that allows for the identification, measurement, monitoring and management of cybersecurity risks. Further, the Corporation and each of the utilities continually consider investments required in security, in both the corporate and grid environments, during the development of the five-year Capital Plan. Physical and cyber security leaders share best practices in areas such as threat monitoring, protecting customer information and risk management. The group also conducts training exercises to test systems and identify opportunities to improve. Oversight of cybersecurity is the responsibility of Fortis' Vice President, Chief Information Officer as well as the respective boards and executive committees at Fortis and at each utility. The Fortis group of companies have not had any reportable cybersecurity breaches since we began reporting this performance indicator in 2018.

Human Capital Management

Fortis values its 9,200 employees and recognizes that success is dependent on a strong workforce which is safe, supported and empowered. Fortis and its utilities have compensation and benefit programs designed to attract and retain talent. Fortis believes that the foundation for a healthy work environment starts with leadership from the most senior levels of the organization and must be driven by clearly articulated values that are understood and practiced at all levels of the organization.

Fortis has a longstanding corporate-wide talent management strategy that enhances our ability to identify, mentor and develop current executives and employees for more senior positions. The Corporation seeks to continually enhance its talent management strategy. In 2022, it completed the inaugural year of a new leadership training program for high-potential employees across the organization that provides substantive training, mentoring opportunities and exposure to management. This approach supports talent development and ensures there is a pipeline of qualified talent, preparing the Corporation and its utilities for an orderly succession of critical roles.

Our utilities strive to maintain good employee and labour relations and regular communications and collaboration between union and management leaders. Approximately 50% of the employees across our group of companies are represented by a labour union.

Governance & Executive Compensation

The Fortis Code of Conduct is guided by the Corporation's purpose and values and sets out standards for the ethical conduct of its directors, officers, employees, consultants, contractors and representatives. The core principles of the Code of Conduct apply 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 and Board members annually certify compliance.

The Code of Conduct is supported by other policies that outline the actions and behaviours 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.

Fortis and each of its operating subsidiaries have a Speak Up Policy to support and facilitate the anonymous reporting of conduct that may breach the Code of Conduct or other workplace policies.

Achieving Fortis' sustainability objectives is a focus for the Board and forms a component of executive compensation. Sustainability-related performance measures including ESG leadership, carbon reduction, safety and reliability, and diversity, equity and inclusion are embedded in the Corporation's executive compensation program.

Diversity, Equity and Inclusion

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 maintain a Board where at least 40% of independent directors are women. As of December 31, 2022, 54% of Board members were women, 42% of Fortis' executives were women and 73% of Fortis utilities had either a female president or female board chair. The Corporation also committed to have at least two Board members who identify as a visible minority or Indigenous person by 2023, and achieved this objective as of December 31, 2022.

Advancing diversity, equity and inclusion is a priority at Fortis. The Corporation adopted an Inclusion and Diversity Commitment that applies to all employees of Fortis and its operating subsidiaries. The commitment is supported by a framework built upon three pillars - talent, culture and community. A Diversity, Equity and Inclusion Advisory Council with diverse, senior level representation from across the Fortis organization guides the inclusion and diversity strategy and its implementation.

OPERATING RESULTS

			Variance	
($ millions)	**2022**	2021	FX	Other
Revenue	**11,043**	9,448	206	1,389
Energy supply costs	**3,952**	2,951	55	946
Operating expenses	**2,683**	2,523	61	99
Depreciation and amortization	**1,668**	1,505	30	133
Other income, net	**165**	173	4	(12)
Finance charges	**1,102**	1,003	22	77
Income tax expense	**289**	234	7	48
Net earnings	**1,514**	1,405	35	74
Net earnings attributable to:				
Non-controlling interests	**120**	111	4	5
Preference equity shareholders	**64**	63	—	1
Common equity shareholders	**1,330**	1,231	31	68
Net Earnings	**1,514**	1,405	35	74

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) higher flow-through costs in customer rates, driven by higher commodity prices; (ii) Rate Base growth; and (iii) higher retail and wholesale electricity sales, as well as transmission revenue, at UNS Energy, partially offset by the normal operation of regulatory deferrals at FortisBC Energy.

Energy Supply Costs

The increase in energy supply costs, net of foreign exchange, was due primarily to higher commodity costs reflecting increases in pricing and volumes.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to general inflationary and employee-related cost increases, as well as the implementation of a new CIS at Central Hudson, partially offset by lower stock-based compensation costs.

Depreciation and Amortization

The increase in depreciation and amortization, net of foreign exchange, was due to continued investment in energy infrastructure at the Corporation's regulated utilities, as well as new depreciation rates, recoverable in customer rates, at ITC effective January 1, 2022.

Other Income, Net

The decrease in other income, net of foreign exchange, was due primarily to losses on total return swaps and foreign exchange contracts in the Corporate and Other segment, as well as losses on investments that support retirement benefits at UNS Energy and ITC. The decrease was largely offset by an increase in the non-service component of benefit costs.

Finance Charges

The increase in finance charges, net of foreign exchange, was due to higher debt levels to support the Corporation's Capital Plan, as well as higher interest rates impacting variable-rate debt and new debt issuances.

Income Tax Expense

The increase in income tax expense, net of foreign exchange, was driven by: (i) higher earnings before taxes; (ii) the revaluation of deferred income tax assets resulting from a reduction in the corporate income tax rate in the state of Iowa; and (iii) a lower income tax recovery in the Corporate & Other segment, including a lower benefit associated with filing a consolidated U.S. tax return and the timing of true-ups to the income tax provision to reflect tax filings.

Net Earnings

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

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

($ millions)	2022	2021	Variance FX [1]	Variance Other
Regulated Utilities				
ITC	**454**	426	16	12
UNS Energy	**328**	292	12	24
Central Hudson	**103**	93	3	7
FortisBC Energy	**203**	185	—	18
FortisAlberta	**151**	141	—	10
FortisBC Electric	**64**	59	—	5
Other Electric [2]	**134**	118	2	14
	1,437	1,314	33	90
Non-Regulated				
Energy Infrastructure [3]	**72**	38	—	34
Corporate and Other [4]	**(179)**	(121)	(2)	(56)
Common Equity Earnings	**1,330**	1,231	31	68

[1] The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and Fortis Belize is the U.S. dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the U.S. dollar at BZ$2.00=US$1.00. The Corporate and Other segment includes certain transactions denominated in U.S. dollars
[2] Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Wataynikaneyap Partnership; Caribbean Utilities; FortisTCI; and Belize Electricity
[3] Primarily consists of long-term contracted generation assets in Belize and Aitken Creek in British Columbia
[4] Includes Fortis net corporate expenses and non-regulated holding company expenses

ITC

($ millions)	2022	2021	Variance FX	Variance Other
Revenue [1]	**1,906**	1,691	63	152
Earnings [1]	**454**	426	16	12

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

Revenue

The increase in revenue, net of foreign exchange, was due primarily to higher recoverable depreciation expense, reflecting revised depreciation rates effective January 1, 2022, and Rate Base growth.

Earnings

The increase in earnings, net of foreign exchange, reflected Rate Base growth and lower non-recoverable stock-based compensation costs. Growth in earnings was tempered by certain discrete items including: (i) costs associated with the suspension of the Lake Erie Connector project; (ii) the revaluation of deferred income tax assets resulting from a reduction in the corporate income tax rate in the state of Iowa; and (iii) a favourable adjustment recognized in 2021 related to interest rate swaps. Losses on certain investments that support retirement benefits and higher holding company finance costs also unfavourably impacted results.

In July 2022, ITC suspended development activities and commercial negotiations relating to the $1.7 billion Lake Erie Connector project. ITC determined that there was no viable path to conclude certain key commercial negotiations and other requirements within the required timelines, in part due to macroeconomic conditions, including rising inflation, interest rates, and fluctuations in the U.S.-to-Canadian dollar foreign exchange rate. This project was never included in the Corporation's five-year Capital Plan.

UNS Energy

			Variance	
($ millions, except as indicated)	**2022**	2021	FX	Other
Retail electricity sales *(GWh)*	**10,658**	10,559	—	99
Wholesale electricity sales *(GWh)* [(1)]	**5,401**	6,283	—	(882)
Gas sales *(PJ)*	**16**	16	—	—
Revenue	**2,758**	2,334	93	331
Earnings	**328**	292	12	24

(1) *Primarily short-term wholesale sales*

Sales

The increase in retail electricity sales was due primarily to favourable weather as compared to 2021 and customer growth.

The decrease in wholesale electricity sales was driven by lower short-term wholesale electricity sales, partially offset by higher long-term wholesale electricity sales. Revenue from short-term wholesale electricity sales is primarily credited to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

Gas sales were consistent with 2021.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) the recovery of higher fuel and non-fuel costs through the normal operation of regulatory mechanisms; (ii) higher revenue from short-term wholesale electricity sales due to favourable pricing; (iii) higher long-term wholesale electricity sales; (iv) higher retail electricity sales, discussed above; and (v) higher transmission revenue. The increase was partially offset by lower short-term wholesale electricity sales.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to higher retail electricity sales, long-term wholesale electricity sales, and transmission revenue. The increase in earnings was partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates, higher operating expenses, and losses on certain investments that support retirement benefits.

Central Hudson

			Variance	
($ millions, except as indicated)	**2022**	2021	FX	Other
Electricity sales *(GWh)*	**5,002**	5,000	—	2
Gas sales *(PJ)*	**25**	23	—	2
Revenue	**1,325**	1,000	36	289
Earnings	**103**	93	3	7

Sales

Electricity sales were consistent with 2021.

The increase in gas sales was due to higher average consumption by residential, commercial and industrial customers due to colder temperatures.

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: (i) the flow through of higher energy supply costs driven by commodity prices; and (ii) an increase in gas and electricity delivery rates effective July 1, 2021 and July 1, 2022, reflecting a return on increased Rate Base assets and the recovery of higher operating and finance expenses, associated with the conclusion of Central Hudson's general rate application in 2021.

Earnings

The increase in earnings, net of foreign exchange, was due to new customer rates discussed above, and the impact of unfavourable regulatory deferrals recorded in 2021 associated with reliability performance targets. The increase was partially offset by higher operating expenses associated with the implementation of a new CIS, and higher non-recoverable finance costs.

FortisBC Energy

($ millions, except as indicated)	**2022**	2021	Variance
Gas sales *(PJ)*	**231**	228	3
Revenue	**2,084**	1,715	369
Earnings	**203**	185	18

Sales

The increase in gas sales was due primarily to higher average consumption by residential and commercial customers due to colder temperatures, partially offset by lower average consumption by transportation customers.

Revenue

The increase in revenue was due primarily to a higher cost of natural gas recovered from customers and Rate Base growth, partially offset by the normal operation of regulatory deferrals.

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

($ millions, except as indicated)	**2022**	2021	Variance
Electricity deliveries *(GWh)*	**16,923**	16,643	280
Revenue	**680**	644	36
Earnings	**151**	141	10

Deliveries

The increase in electricity deliveries was due to higher load from industrial customers, higher average consumption by commercial customers, and customer additions. The increase was partially offset by lower average consumption by residential customers due to milder weather in 2022 as compared to 2021.

As approximately 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. Significant variations in weather conditions, however, can impact revenue and earnings.

Revenue

The increase in revenue was due to Rate Base growth.

Earnings

The increase in earnings was due to Rate Base growth, partially offset by higher operating expenses and a higher effective income tax rate.

FortisBC Electric

($ millions, except as indicated)	2022	2021	Variance
Electricity sales (GWh)	**3,542**	3,460	82
Revenue	**487**	468	19
Earnings	**64**	59	5

Sales

The increase in electricity sales was due primarily to higher average consumption by industrial customers.

Revenue

The increase in revenue was due to higher electricity sales, Rate Base growth, and higher surplus power sales, partially offset by the normal operation of regulatory deferrals.

Earnings

The increase in earnings was due primarily to Rate Base growth.

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

Other Electric

			Variance	
($ millions, except as indicated)	2022	2021	FX	Other
Electricity sales (GWh)	**9,470**	9,266	—	204
Revenue	**1,652**	1,498	14	140
Earnings	**134**	118	2	14

Sales

The increase in electricity sales was due to higher average consumption by residential and commercial customers in Eastern Canada, as well as higher sales in the Caribbean, due to increased tourism-related activities.

Revenue

The increase in revenue, net of foreign exchange, was due to the flow through of higher energy supply costs, higher electricity sales and Rate Base growth, as well as the normal operation of regulatory mechanisms at Newfoundland Power.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth and higher electricity sales.

Energy Infrastructure

($ millions, except as indicated)	2022	2021	Variance
Electricity sales (GWh)	**225**	147	78
Revenue	**151**	98	53
Earnings	**72**	38	34

Sales

The increase in electricity sales reflected an increase in hydroelectric production in Belize associated with higher rainfall levels.

Revenue and Earnings

Revenue and earnings were favourably impacted by the mark-to-market accounting of natural gas derivatives at Aitken Creek, which resulted in unrealized gains of $20 million in 2022 compared to $12 million in 2021.

Excluding the impact of mark-to-market accounting, revenue and earnings increased by $43 million and $26 million, respectively. The increases were driven by Aitken Creek due to higher margins on gas sold, reflecting market conditions, as well as losses realized on natural gas contracts in 2021, as certain contracts were settled that year in consideration of favourable forward curves. Higher hydroelectric production in Belize also contributed to the increases in revenue and earnings.

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

($ millions)	2022	2021	Variance FX	Variance Other
Net expenses	**(179)**	(121)	(2)	(56)

The increase in net expenses, net of foreign exchange, largely reflected market conditions, including losses on total return swaps and foreign exchange contracts, as well as higher finance costs. A lower income tax recovery also contributed to results. The increase in net expenses was partially offset by a reduction in operating expenses reflecting lower stock-based compensation costs.

Results for the Corporate and Other segment include the impact of hedging activities associated with share-based compensation and foreign exchange, and therefore can fluctuate depending on market conditions. On a consolidated basis, the overall earnings impact was favourable as lower stock based compensation costs and the translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate was greater than losses on derivatives associated with hedging activities.

NON-U.S. GAAP FINANCIAL MEASURES

Adjusted Common Equity Earnings, Adjusted Basic EPS, Adjusted Payout Ratio and Capital Expenditures are Non-U.S. 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 U.S. 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 U.S. GAAP measure to the Adjusted Payout Ratio. These adjusted measures reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results.

Capital Expenditures include additions to property, plant and equipment and additions to intangible assets, as shown on the consolidated statements of cash flows. It also includes Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, consistent with Fortis' evaluation of operating results and its role as project manager during the construction of this Major Capital Project.

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	2022	2021	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,330**	1,231	99
Adjusting items:			
Unrealized gain on mark-to-market of derivatives (1)	**(20)**	(12)	(8)
Lake Erie Connector project suspension costs (2)	**10**	—	10
Revaluation of deferred income tax assets (3)	**9**	—	9
Adjusted Common Equity Earnings	**1,329**	1,219	110
Adjusted Basic EPS (4) ($)	**2.78**	2.59	0.19
Adjusted Payout Ratio (5) (%)	**78.1**	79.2	(1.1)
Capital Expenditures			
Additions to property, plant and equipment	**3,587**	3,189	398
Additions to intangible assets	**278**	197	81
Adjusting item:			
Wataynikaneyap Transmission Power Project (6)	**169**	178	(9)
Capital Expenditures	**4,034**	3,564	470

(1) Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $7 million in 2022 (2021 - $5 million), included in the Energy Infrastructure segment
(2) Represents costs incurred upon the suspension of the Lake Erie Connector project, net of income tax recovery of $4 million, included in the ITC segment
(3) Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa, included in the ITC segment
(4) Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 478.6 million in 2022 (2021 - 470.9 million)
(5) Calculated using dividends paid per common share of $2.17 in 2022 (2021 - $2.05) divided by Adjusted Basic EPS
(6) Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric 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 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 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.

Transmission operations in the U.S. are regulated federally by FERC. Remaining utility operations in the U.S. 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 2022 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 25.

Significant Regulatory Developments

ITC

ITC Midwest Capital Structure Complaint: In May 2022, ICAT filed a complaint with FERC under Section 206 of the Federal Power Act requesting that ITC Midwest's common equity component of capital structure be reduced from 60% to 53%. ICAT alleged that ITC Midwest does not meet FERC's three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In November 2022, FERC issued an order denying the complaint, and in December 2022, ICAT filed a request for rehearing with FERC. The Corporation continues to believe the complaint is without merit, and as at December 31, 2022, ITC Midwest has not recorded a regulatory liability related to the complaint.

MISO Base ROE: In August 2022, the D.C. Circuit Court issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the MISO region, including ITC. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect. The court has remanded the matter to FERC for further process, the timing and outcome of which is unknown. Although any potential impact to Fortis is uncertain, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

Transmission Incentives: In 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding is unknown.

UNS Energy

TEP General Rate Application: In June 2022, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2023 using a December 31, 2021 test year. The application reflects a US$136 million net increase in non-fuel and fuel-related revenue, as well as proposals to eliminate certain adjustor mechanisms, and modify an existing adjustor to provide more timely recovery of clean energy investments. The timing and outcome of this proceeding is unknown.

Central Hudson

CIS Implementation: In December 2022, the PSC released a report into the deployment by Central Hudson of its new CIS. The PSC also issued an Order to Commence Proceeding and Show Cause, which directed Central Hudson to explain why the PSC should not pursue civil or administrative penalties or initiate a proceeding to review the prudence of the CIS implementation costs. Central Hudson was also required to submit a plan to eliminate bi-monthly bill estimates and to evaluate the customer impacts of such a change. Central Hudson's response was filed in January 2023. The timing and outcome of this proceeding is unknown.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In 2021, the BCUC initiated a proceeding including a review of the common equity component of capital structure and the allowed ROE. FortisBC filed a final argument with the BCUC in December 2022 and the proceeding remains ongoing, with a decision expected in the second quarter of 2023.

FortisAlberta

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for Alberta regulated utilities for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. In March 2022, the AUC issued a decision extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. The GCOC proceeding for 2024 and beyond remains ongoing, and a decision is expected in the third quarter of 2023.

2023 COS Application: In July 2022, the AUC issued a decision largely accepting the forecast requested in FortisAlberta's COS application. The associated compliance filing, including the updated 2023 revenue requirement, was approved by the AUC in December 2022.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta is participating in this proceeding and a decision from the AUC is expected in 2023.

REA Cost Recovery: In 2021, the AUC determined that costs attributable to REAs, approximating $10 million annually, can no longer be recovered from FortisAlberta's rate payers, effective January 1, 2023. FortisAlberta filed an appeal with the Alberta Court of Appeal, asserting that the AUC erred in preventing the company from recovering these costs from its own rate payers to the extent that such costs cannot be recovered directly from REAs. The appeal was heard in December 2022, and a decision from the Court is expected in first quarter of 2023.

FINANCIAL POSITION

Significant Changes between December 31, 2022 and 2021

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Accounts receivable and other current assets	**56**	**772**	Due to: (i) the flow through of higher energy supply costs; (ii) an increase in the fair value of energy contracts at UNS Energy; (iii) higher wholesale electricity revenue at UNS Energy; and (iv) slower collections at Central Hudson.
Inventories	**26**	**157**	Reflects an increase in the cost and amount of natural gas in storage.
Other assets	**57**	**201**	Reflects an increase in the fair value of energy contracts at UNS Energy and equity contributions associated with the Wataynikaneyap Power project.
Regulatory assets (current and long-term)	**87**	**333**	Due to: (i) the normal operation of rate stabilization accounts, reflecting the flow through of higher commodity costs; (ii) the deferral of incremental restoration costs associated with significant weather events; (iii) unrealized losses on natural gas derivatives at FortisBC Energy; and (iv) higher energy management costs to be recovered in customer rates. The increase was partially offset by the normal operation of employee future benefit deferrals.
Property, plant and equipment, net	**1,722**	**2,125**	Due to capital expenditures, partially offset by depreciation.
Intangible assets, net	**71**	**134**	Largely reflects investment in land rights and computer software at UNS Energy, partially offset by amortization.
Goodwill	**744**	**—**	
Accounts payable & other current liabilities	**90**	**628**	Due to: (i) higher energy supply costs; (ii) an increase in trade accounts payable, reflecting the timing of payments; (iii) higher income taxes payable; and (iv) an decrease in the fair value of natural gas derivatives at FortisBC Energy.
Other liabilities	**57**	**(320)**	Reflects a decrease in employee future benefit liabilities driven by higher discount rates.
Regulatory liabilities (current and long-term)	**157**	**536**	Reflects unrealized gains on energy contracts at UNS Energy, which are utilized to reduce exposure to changes in energy prices, and the normal operation of rate stabilization accounts and employee future benefit and future cost of removal deferrals.

Significant Changes between December 31, 2022 and 2021

Balance Sheet Account ($ millions)	Variance FX	Variance Other	Explanation
Deferred income tax liabilities	**154**	**279**	Due to higher temporary differences associated with ongoing capital investment.
Long-term debt (including current portion)	**1,190**	**1,887**	Reflects debt issuances partially offset by debt repayments, and higher borrowings under committed credit facilities, in support of the Corporation's Capital Plan.
Shareholders' equity	**983**	**759**	Due primarily to: (i) Common Equity Earnings for 2022, less dividends declared on common shares; and (ii) the issuance of common shares, largely under the DRIP.
Non-controlling interests	**117**	**67**	Reflects net earnings for 2022, less dividends declared by the Corporation's subsidiaries, attributable to non-controlling interests.

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. Remaining capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's committed credit facility, the operation of 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 financing. Financing needs also arise to refinance maturing debt.

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the total revolving credit facilities. Approximately $5.6 billion of the total credit facilities are committed with maturities ranging from 2023 through 2027. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 ($ millions)	Regulated Utilities	Corporate and Other	2022	2021
Total credit facilities [1]	3,795	2,055	**5,850**	4,846
Credit facilities utilized:				
Short-term borrowings	(253)	—	**(253)**	(247)
Long-term debt (including current portion)	(922)	(735)	**(1,657)**	(1,305)
Letters of credit outstanding	(76)	(52)	**(128)**	(115)
Credit facilities unutilized	2,544	1,268	**3,812**	3,179

[1] *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2022 Annual Financial Statements*

In 2022, Central Hudson increased its available credit facilities from US$230 million to US$320 million.

In May 2022, the Corporation amended its unsecured $1.3 billion revolving term committed credit facility agreement to extend the maturity to July 2027, and to establish a sustainability-linked loan structure based on the Corporation's achievement of targets for diversity on the Board and Scope 1 GHG emissions for 2022 through 2025. Maximum potential annual margin pricing adjustments are +/- 5 basis points and +/- 1 basis point for drawn and undrawn funds, respectively.

Also in May 2022, the Corporation entered into an unsecured US$500 million non-revolving term credit facility. The facility has an initial one-year term, is repayable at any time without penalty, provides the Corporation with additional, cost effective short-term financing and liquidity, and enhances financial flexibility.

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, 2022, consolidated fixed-term debt maturities/repayments are expected to average $1,437 million annually over the next five years and approximately 73% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In November 2022, 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, 2022, $2.0 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity. 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 2023.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2022 and are expected to remain compliant in 2023.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

($ millions)	**2022**	2021	Variance
Cash and cash equivalents, beginning of year	**131**	249	(118)
Cash from (used in):			
Operating activities	**3,074**	2,907	167
Investing activities	**(4,059)**	(3,488)	(571)
Financing activities	**1,035**	451	584
Effect of exchange rate changes on cash and cash equivalents	**28**	12	16
Cash and cash equivalents, end of year	**209**	131	78

Operating Activities

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

Investing Activities

The increase in cash used in investing activities reflects higher capital expenditures in 2022, as well as the higher U.S.-to-Canadian dollar exchange rate. See "Performance at a Glance - Capital Expenditures" on page 5 and "Capital Plan" on page 21. Planned equity contributions associated with the Wataynikaneyap Power project in 2022 also impacted the use of cash as compared to the prior year.

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 17.

Debt Financing

Long-Term Debt Issuances

Year ended December 31, 2022	Month Issued	Interest Rate (%)	Maturity	Amount ($ millions)		Use of Proceeds
ITC						
Secured first mortgage bonds	January	2.93	2052	**US**	**150**	(1) (2) (3) (4)
Secured senior notes	May	3.05	2052	**US**	**75**	(1) (3) (4)
Unsecured senior notes	September	4.95 (5)	2027	**US**	**600**	(1) (4) (6)
Secured first mortgage bonds	October	3.87	2027	**US**	**75**	(2)
Secured first mortgage bonds	October	4.53	2052	**US**	**75**	(2)
UNS Energy						
Unsecured senior notes	February	3.25	2032	**US**	**325**	(4) (6)
Central Hudson						
Unsecured senior notes	January	2.37	2027	**US**	**50**	(4) (6)
Unsecured senior notes	January	2.59	2029	**US**	**60**	(4) (6)
Unsecured senior notes	September	5.07	2032	**US**	**100**	(1) (4)
Unsecured senior notes	September	5.42	2052	**US**	**10**	(1) (4)
FortisBC Energy						
Unsecured debentures	November	4.67	2052		**150**	(2)
FortisAlberta						
Senior unsecured debentures	May	4.62	2052		**125**	(1)
FortisBC Electric						
Unsecured debentures	March	4.16	2052		**100**	(1)
Newfoundland Power						
First mortgage sinking fund bonds	April	4.20	2052		**75**	(1) (4) (6)
Caribbean Utilities						
Unsecured senior notes	November	5.88	2052	**US**	**80**	(1) (3)
Fortis						
Unsecured senior notes	May	4.43 (7)	2029		**500**	(4) (8)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund or refinance, in part or in full, a portfolio of new and/or existing eligible green projects*
(3) *Fund capital expenditures*
(4) *General corporate purposes*
(5) *ITC entered into interest rate swaps which reduced the effective interest rate to 3.54%. See Note 25 to the 2022 Annual Financial Statements*
(6) *Repay maturing long-term debt*
(7) *The Corporation entered into cross-currency interest rate swaps to effectively convert the debt into US$391 million with an interest rate of 4.34%. See Note 25 to the 2022 Annual Financial Statements*
(8) *Fund the June 2022 redemption of the Corporation's $500 million, 2.85% senior unsecured notes due December 2023*

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31 *($ millions, except as indicated)*	2022	2021	Variance
Common shares issued:			
Cash (1)	**53**	60	(7)
Non-cash (2)	**366**	358	8
Total common shares issued	**419**	418	1
Number of common shares issued *(# millions)*	**7.4**	8.0	(0.6)
Common share dividends paid:			
Cash	**(673)**	(608)	(65)
Non-cash (3)	**(364)**	(356)	(8)
Total common share dividends paid	**(1,037)**	(964)	(73)
Dividends paid per common share *($)*	**2.17**	2.05	0.12

(1) *Includes common shares issued under stock option and employee share purchase plans*
(2) *Common shares issued under the DRIP and stock option plan*
(3) *Common share dividends reinvested under the DRIP*

On November 17, 2022 and February 9, 2023, Fortis declared a dividend of $0.565 per common share payable on March 1, 2023 and June 1, 2023, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

Contractual Obligations

Contractual Obligations

As at December 31, 2022

($ millions)	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [(1)]	**28,578**	2,481	1,434	518	2,434	1,977	19,734
Interest	**17,159**	1,105	1,056	1,020	988	908	12,082
Finance leases [(2)]	**1,177**	35	35	35	35	36	1,001
Other obligations [(3)]	**422**	116	86	77	30	29	84
Other commitments: [(4)]							
Gas and fuel purchase obligations	**5,720**	1,024	516	461	374	328	3,017
Waneta Expansion capacity agreement	**2,472**	54	55	56	58	59	2,190
Renewable power purchase agreements	**1,926**	131	131	131	131	130	1,272
Power purchase obligations	**1,691**	334	253	191	192	113	608
ITC easement agreement	**380**	14	14	14	14	14	310
Debt collection agreement	**106**	3	3	3	3	3	91
Renewable energy credit purchase agreements	**77**	18	14	7	7	6	25
Other	**132**	21	9	20	3	3	76
	59,840	5,336	3,606	2,533	4,269	3,606	40,490

(1) Amounts not reduced by unamortized deferred financing and discount costs of $166 million. Additional information is provided in Note 14 of the 2022 Annual Financial Statements

(2) Additional information is provided in Note 15 of the 2022 Annual Financial Statements

(3) Primarily includes commitments with respect to long-term compensation and employee future benefit arrangements

(4) Represents unrecorded commitments. Additional information is provided in Note 26 of the 2022 Annual Financial Statements

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $4.3 billion for 2023 and approximately $22.3 billion over the five-year 2023-2027 Capital Plan. See "Capital Plan" on page 21.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. The Wataynikaneyap Partnership has loan agreements in place 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 Four Corners and Luna, with agreements expiring in 2041 and 2046, respectively, and at San Juan and 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 San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $339 million for Four Corners. As at December 31, 2022, 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 $74 million, for which it has issued a parental guarantee. As at December 31, 2022, there was no obligation under this guarantee.

As at December 31, 2022, FortisBC Holdings Inc., a non-regulated holding company, had $142 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 $128 million as at December 31, 2022 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	2022 ($ millions)	2022 (%)	2021 ($ millions)	2021 (%)
Debt [1]	**28,792**	**55.8**	25,784	55.2
Preference shares	**1,623**	**3.1**	1,623	3.5
Common shareholders' equity and non-controlling interests [2]	**21,219**	**41.1**	19,293	41.3
	51,634	**100.0**	46,700	100.0

(1) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*

(2) *Includes shareholders equity, net of preference shares, and non-controlling interests. Non-controlling interests represented 3.5% as at December 31, 2022 (December 31, 2021 - 3.5%)*

Outstanding Share Data

As at February 9, 2023, the Corporation had issued and outstanding 482.2 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 9, 2023, an additional 2.3 million common shares would be issued and outstanding.

Credit Ratings

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

As at December 31, 2022	Rating	Type	Outlook
S&P	A-	Corporate	Stable
	BBB+	Unsecured debt	
DBRS Morningstar	A (low)	Corporate	Stable
	A (low)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

In December 2022, S&P lowered Central Hudson’s unsecured debt credit rating to BBB+ from A- and revised the rating outlook to stable from negative. S&P noted that the change was due to projected weakening in the company’s financial measures due to the effects of rising inflation and higher interest rates combined with an elevated capital spending program and increasing operations and maintenance costs.

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, to meet customer growth, and to deliver cleaner energy.

Capital Expenditures of $4.0 billion were consistent with the 2022 Capital Plan, with $600 million of capital investment focused on delivering cleaner energy to customers.

2022 Capital Expenditures [1]

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**
Total	1,212	709	293	589	510	130	562	**4,005**	**29**	**4,034**

(1) *See "Non-U.S. GAAP Financial Measures" on page 14*

(2) *Energy Infrastructure segment*

Forecast 2023 Capital Expenditures [1][2]

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Total Regulated Utilities	Non-Regulated	Total
Total	1,103	1,006	384	536	556	132	579	**4,296**	**31**	**4,327**

(1) *Represents a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 14.*
(2) *Excludes the non-cash equity component of AFUDC*

2023-2027 Capital Plan [1]

($ billions)	2023	2024	2025	2026	2027	Total [2][3]
Five-year capital plan	4.3	4.2	4.5	4.5	4.8	**22.3**

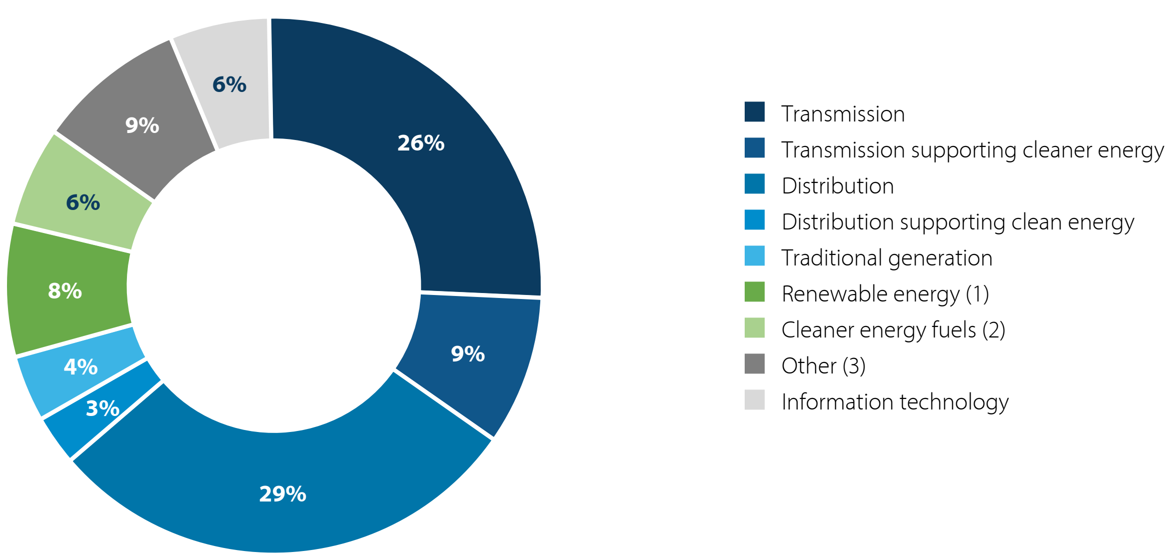
(1) *Capital Plan is a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 14*
(2) *Reflects an assumed U.S.:CAD foreign exchange rate of 1.30. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $500 million over the five-year planning period*
(3) *Excludes the non-cash equity component of AFUDC*

The 2023-2027 Capital Plan is $2.3 billion higher than the prior five-year plan that totalled $20 billion. The increase is driven by organic growth, largely reflecting regional transmission projects associated with the MISO LRTP at ITC, additional cleaner energy investments in Arizona to support TEP's planned exit from coal by 2032, and enhancements to distribution infrastructure reliability and capacity, as well as investments to support customer growth, across the Corporation's regulated utilities. Approximately $500 million of the increase is driven by a higher assumed U.S.-to-Canadian dollar exchange rate over the five-year period.

In total, Fortis expects to invest $5.9 billion in cleaner energy over the next five years. These investments will focus on connecting renewables to the grid, including Tranche 1 of MISO's LRTP, renewable and storage investments in Arizona and the Caribbean, and cleaner fuel solutions in British Columbia. The plan incorporates key customer affordability considerations, recognizing the impacts of inflation and elevated commodity costs on customer rates, while ensuring reliable and resilient energy delivery service as we transition to a cleaner energy future.

The investments included in the 2023-2027 Capital Plan are summarized as follows:

Five-Year Capital Plan



(1) *Includes clean generation and battery storage*
(2) *Includes RNG and LNG*
(3) *Includes facilities, equipment and vehicles not included in other categories*

The Capital Plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 17% relating to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the U.S., including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Planned Capital Expenditures are based on forecasts of energy demand as well as labour and material costs, including inflation, supply chain availability, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast.

While global supply chain constraints and rising inflation remain issues of potential concern that continue to evolve, the Corporation does not expect a material impact on its 2023-2027 Capital Plan, although certain planned expenditures may shift within the five years. The Corporation continues to proactively work to mitigate supply chain constraints by identifying high priority materials and consolidating buying power to improve outcomes, increasing inventory levels, and closely working with suppliers to ensure material availability.

Midyear Rate Base [1]

($ billions)	**2022**	2023	2027
ITC	**10.5**	11.1	14.1
UNS Energy	**6.7**	7.0	9.1
Central Hudson	**2.6**	2.7	3.6
FortisBC Energy	**5.4**	5.8	7.6
FortisAlberta	**4.0**	4.2	5.0
FortisBC Electric	**1.6**	1.7	2.0
Other Electric	**3.3**	3.8	4.7
Total	**34.1**	36.3	46.1

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

Total midyear Rate Base is forecast to grow to $46.1 billion by 2027 underpinned by the five-year Capital Plan, representing a CAGR of 6.2%.

Major Capital Projects [1]

($ millions)	Pre-2022	**Actual 2022**	Forecast 2023	Forecast 2024-2027	Expected Completion
ITC					
MISO LRTP	—	**—**	—	923	Post-2027
UNS Energy					
Renewable Generation	—	**—**	—	417	Various
Vail-to-Tortolita Transmission Project	21	**46**	106	272	2027
FortisBC Energy					
Tilbury LNG Storage Expansion	16	**9**	17	487	Post-2027
AMI Project	—	**3**	11	410	Post-2027
Eagle Mountain Woodfibre Gas Line Project [2]	—	**—**	—	420	2027
Tilbury 1B Project	29	**11**	27	316	Post-2027
Okanagan Capacity Upgrade	16	**3**	12	188	2025
Other Electric					
Wataynikaneyap Transmission Power Project [3]	355	**169**	117	20	2024
Total		**241**	290	3,453	

(1) *Includes applicable AFUDC*
(2) *Net of forecast customer contributions*
(3) *Fortis' share of estimated capital spending. Under the funding framework, Fortis will be funding its equity component only.*

MISO LRTP
In July 2022, the MISO board approved the first tranche of projects associated with the LRTP, representing 18 transmission projects across the MISO Midwest subregion with total associated costs estimated at US$10 billion. Six of these projects run through ITC's MISO operating companies' service territories, including Michigan and Iowa, where right of first refusal provisions currently exist for incumbent transmission owners. ITC estimates transmission investments of US$1.4 billion to US$1.8 billion through 2030 associated with six of the 18 projects, with capital expenditures of approximately $900 million (US$700 million) included in the Corporation's 2023-2027 Capital Plan. Other projects within ITC's MISO service territory may be subject to competitive bidding, depending on the state in which they are located.

Renewable Generation
Planned renewable generation investments supporting the transition to cleaner energy as outlined in TEP's 2020 IRP. Excludes energy storage investments which are not yet defined. In February 2022, the ACC acknowledged TEP's 2020 IRP, and found it to be reasonable and in the public interest.

Vail-to-Tortolita Transmission Project
Construction and upgrades to connect existing TEP substations to a new 230kV line within TEP’s service territory. Construction is expected to begin in 2023 with an anticipated completion date of 2027.

Tilbury LNG Storage Expansion
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. FortisBC Energy has filed a CPCN application for this project with the BCUC, and if approved, the project is expected to begin in 2023.

AMI Project
Replacement of residential and small commercial meters with advanced meters and installation of bypass valves to support the safety, resiliency, and efficient operation of the gas distribution system. FortisBC Energy has filed a CPCN application with the BCUC for this project.

Eagle Mountain Woodfibre Gas Line Project
Gas line expansion to a proposed LNG site in Squamish, British Columbia. In April 2022, Woodfibre LNG Limited issued a Notice to Proceed to its prime contractor with respect to the project, however, the project remains contingent on certain conditions of Woodfibre LNG Limited and on FortisBC Energy receiving the remaining regulatory and permitting approvals.

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. An initial project scope has been filed with regulators to support the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2023.

Okanagan Capacity Upgrade
Construction of a new section of pipeline and associated facilities to address expected load growth in the Okanagan region. FortisBC Energy has filed a CPCN application with the BCUC for this project.

Wataynikaneyap Transmission Power Project
Construction of an 1,800 kilometer, OEB-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. In August 2022, Phase 1 of the project was completed, energizing the 230 kV line from Dinorwic to Pickle Lake, Ontario. As at December 31, 2022, the project was 73% complete, with 700 kilometers of transmission line energized and three First Nation communities connected to the Ontario electric grid. Construction is expected to be completed in 2024.

Additional Investment Opportunities

Fortis is pursuing additional investment opportunities within existing service territories that are not yet included in the five-year Capital Plan.

Inflation Reduction Act of 2022
In August 2022, the IRA was passed into U.S. law which included, among other items, a focus on energy security and climate change programs. With incentives and clean energy tax credits encouraging investments in clean energy, energy storage, electric vehicles and manufacturing, the IRA aligns with Fortis' cleaner energy goals and provides an opportunity for continued investment in a cleaner energy future.

ITC - MISO LRTP
The MISO LRTP is expected to consist of four tranches. Incremental opportunity associated the first tranche of projects is outlined above. MISO is expected to identify projects associated with the second tranche of the LRTP in the first half of 2024, which is expected to provide further investment opportunities at ITC.

UNS Energy - TEP 2020 IRP
The TEP 2020 IRP outlines the resource energy transition required to meet customers' energy needs through 2035 as TEP exits coal-fired resources by 2032 and replaces it with wind and solar resources. This transition is expected to reduce carbon emissions 80 percent by 2035. This plan supports reliable and affordable service from sustainable resources and is expected to provide incremental capital investment opportunity of US$2 billion to US$4 billion through 2035. The IRP may be impacted by various federal and state energy policies, including policies currently under consideration. TEP is expected to file its 2023 IRP with the ACC in the second half of 2023.

FortisBC Energy - LNG
LNG infrastructure opportunities in British Columbia include 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 close to international shipping lanes.

With respect to further Tilbury expansion, in July 2022, FortisBC Energy's parent company, FortisBC Holdings Inc., entered into an agreement with an Indigenous community to provide the ability to participate, through equity ownership, in certain future LNG investments if the parties are able to satisfy certain obligations. Any proposed transaction is subject to regulatory approvals and certain conditions precedent.

Other Opportunities
Includes incremental regulated transmission investment and grid modernization projects at ITC; energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and cleaner energy infrastructure, as well as climate change adaptation investments across our jurisdictions.

BUSINESS RISKS

Fortis has an ERM program that identifies and evaluates the severity and probability of risks to its business. The Fortis Board, through its audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning. The ERM program at the subsidiary level is overseen by each subsidiary's board of directors and any material risks identified form part of Fortis' ERM program. Materiality thresholds are reviewed annually. Systems of internal controls are used by management to monitor and manage identified risks. A summary of the Corporation's significant business risks follows.

Utility Regulation

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2022. Regulatory jurisdictions include five Canadian provinces, nine U.S. states and three Caribbean countries, as well FERC regulation for transmission assets in the U.S.

Regulators administer legislation covering material aspects of the utilities' business including: customer rates, 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 by its regulator in setting customer rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends upon achieving the forecasts established in the rate-setting process. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could adversely affect rates of return. Failure to recover costs and/or earn a return could have a Material Adverse Effect.

For transmission operations, the underlying elements of FERC-established formula rates can be challenged by third parties which could result in rate reductions and customer refunds. These underlying elements include the ROE, ROE adders and deemed capital structure, as well as operating and capital expenditures.

In addition, the U.S. 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 U.S. federal energy matters.

While Fortis is well-positioned to maintain constructive regulatory relationships through local management teams and subsidiary board of directors comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors. The Corporation and its utilities may experience challenges and compliance costs in responding to such regulatory changes in an effective and timely manner. Any such regulatory changes or operational impacts could have a Material Adverse Effect.

Physical Risks

The provision of electric and gas service is subject to physical risks, including impacts from severe weather and natural disasters, wars, terrorism, vandalism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories.

Certain electric utilities operate in remote or 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, hurricanes, storm surges, washouts, landslides, earthquakes, avalanches, snow or ice storms, and other acts of nature. Also, the operation of electricity transmission and distribution assets has the potential to cause fires, mainly as a result of equipment failure, falling trees or lightning strikes to lines or equipment.

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.

Accidents or natural disasters affecting any of the Corporation's electricity or gas utilities can lead to service disruption, spills and commensurate environmental liability, or other liability.

Generating equipment and facilities are subject to physical risks, including equipment breakdown or damage from fire, floods or other natural disasters, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption.

The foregoing 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.

Electricity and gas systems require ongoing maintenance, improvement and replacement. 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.

Service disruption, other effects and liability, whether caused by the failure to properly implement or complete approved maintenance and capital expenditures, severe weather or other physical risks, if not mitigated through insurance policies or the recovery of such costs in customer rates, could result in loss. Any of the foregoing potential impacts of physical risk could have a Material Adverse Effect.

The foregoing physical risks can be intensified by the "Climate Change" risks discussed below.

Climate Change

Climate-Related Physical Risk

Climate change may negatively impact the ability to provide reliable and safe electric and gas service. The changing climate is predicted to lead to more frequent and severe weather events which may impact or disrupt the reliability of electric or gas systems. The physical risks associated with a changing climate and more frequent and intense weather events requires the Corporation’s utilities to respond to continue delivering reliable service to customers.

Severe weather impacts the Corporation's service territories, primarily in the form of thunderstorms, flooding, wildfires, hurricanes, storm surges, atmospheric rivers and snow, or ice storms. Increased frequency of extreme weather events could increase the cost of providing service through increased repairs and use of contingency plans. Extreme weather conditions and changes in air temperature require system backup and can result in system stress, including service disruptions, and decreased efficiency of operating facilities over time. 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.

Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels, larger storm surges and floods, could result in service disruption, shortened asset life, increased repair and replacement costs, and costs associated with strengthened design standards and systems. The impacts of climate change can intensify the "Physical Risks" described on page 25.

The physical risks posed by the impacts of climate change and 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-Related Transition Risk

As economies transition toward decarbonization and increase renewable energy use under various national and international commitments, risks arise related to associated policy, legal, technological and market changes, which may have related capital and financial implications for the Corporation and its utilities.

The impacts of the transition to a cleaner energy future will require the Corporation’s utilities to effectively manage, among other things, evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to appropriately respond to climate change and decarbonize may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts.

Fortis expects the pace of government policy and regulatory changes to accelerate in the coming years (see "Environmental Regulation" on page 27). Further, the emergence of initiatives designed to reduce GHG emissions, increase renewable energy use, and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce renewable energy, enable more efficient storage of energy and reduce energy consumption. As new technologies become widely available, infrastructure design risks and time delays may emerge. Utility energy delivery systems will require technological changes and updates in order to effectively deliver increasing amounts of renewable energy to customers (see "Technology Developments" on page 28).

The availability of regulatory mechanisms or the ability of the Corporation's utilities to pass related costs on to customers remains uncertain. Regulatory lag in relation to the adoption of climate change initiatives and/or the availability of regulatory recovery mechanisms in certain jurisdictions could contribute to financial harm to Fortis and its utilities (see "Utility Regulation" on page 25).

Fortis has a plan to reduce GHG direct emissions 50% by 2030 and 75% by 2035 without the use of carbon offsets or new technology. Technological advancements will be required in order for the Corporation to eliminate the last 25% of its GHG direct emissions by 2050 to achieve its net-zero target while preserving system reliability and customer affordability. In addition to the development and implementation of relevant energy technologies, the Corporation's ability to achieve its climate-related targets depends upon many factors, including the size of the Corporation's service territory, capacity needs remaining in line with current expectations, the impacts of future regulations or legislation, or the adoption of alternative energy products by the public, any of which could cause actual results and the ability to achieve such targets to materially differ from expectations. The ultimate impact of achieving or failing to achieve such targets could cause reputational damage which could result in a Material Adverse Effect.

Growth

Fortis has a history of both growth through acquisitions and organic growth from capital investment in existing service territories. 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 as described under "Capital Plan" on page 21. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by commodity price fluctuations, supply and labour costs, supply chain constraints, 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, which may have a Material Adverse Effect.

Environmental Regulation

The Corporation's businesses are subject to environmental laws and regulations, including those which concern emissions into the air, discharges into water or soil, use of water, hazardous waste disposal and containment, and the investigation and remediation of contamination, among others.

The risk of contamination of air, soil and water associated with electricity operations 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 gas operations 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.

Failure to comply with environmental laws and regulations, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other penalties. Further, liabilities relating to contamination investigation and remediation, and related 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, whether it resulted from non-compliance with applicable environmental laws and regulations, or whether it resulted from any act or omission of the business. These liabilities could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance or through regulatory mechanisms, these foregoing costs could have a Material Adverse Effect.

Environmental laws and regulations continue to develop and may result in significant additional expense. In particular, the management of GHG emissions and related decarbonization requirements is a major concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines. Regulation and the pace of regulatory change to address reliability, resiliency, resource planning and safety is expected to increase in response to climate change. Future legislation could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect (see "Climate Change" at page 26).

Pandemics and Public Health Crises

The Corporation could be negatively impacted by widespread outbreaks of communicable diseases or other public health crises that cause economic and/or other disruptions. Outbreaks of communicable diseases, as well as efforts to reduce the health impacts and control disease spread, can lead to restrictions on business operations, including business closures and the potential impacts of reduced labour availability and productivity, supply chain disruptions, project construction delays, disruptions to capital markets, governmental and regulatory action, 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 (see "General Economic Conditions" on page 29).

The Corporation's utilities provide essential services and must be operational and maintained throughout any pandemic or public health crisis, though such events can challenge operations and increase operating costs. The duration and severity of a pandemic or public health crisis, could have a Material Adverse Effect.

Health and Safety

The operations of the Corporation's utilities inherently involve risk to the health and safety of both employees and the public. Personal injury or loss of life could result from failure to implement or observe appropriate health and safety procedures and gives rise to operational, reputational or financial impacts, any of which could have a Material Adverse Effect. In addition, failure to comply with health and safety regulations could result in fines, penalties, reputational damage, litigation, increased capital and operating costs or adverse regulatory outcomes.

Natural Gas Competitiveness

Approximately 23% of the Corporation's revenue is derived from the delivery of natural gas. In British Columbia, which accounts for 82% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating load. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive due to price or other factors, such as the carbon intensity of natural gas relative to other energy sources, 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 and, in the extreme, could ultimately lead to an inability to recover the utility's cost of service through customer rates.

Government policy could further impact the competitiveness of natural gas in British Columbia. As governments develop policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to other energy sources.

Additionally, there are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as the carbon intensity of the energy source and the type of housing stock being built. 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. Municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Corporation's ability to attract new natural gas customers or retain existing customers.

A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

Cybersecurity and Information and Operations Technology

As operators of critical energy infrastructure, the Corporation's utilities are at risk of cybercrime. The ability of the Corporation's utilities to operate effectively is dependent upon using and maintaining complex information systems and infrastructure that: (i) support the operation of generation, transmission and distribution facilities, including electric and gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations. The Corporation also engages third-party service providers to help facilitate the management of the Corporation's information security systems, communication tools and data processing.

Information and operations technology systems, including those of the Corporation's third-party service providers, may be vulnerable to unauthorized access or disruption due to cyber- and other attacks, including hacking, malware, acts of war or terrorism, and acts of vandalism, among others. Further, geopolitical conflicts may further increase the sophistication, magnitude or frequency of cyberattacks, some of which may even be initiated by nation state actors. Any such event could result in the disruption of energy service and other business operations, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business information or personal information of customers and/or employees.

A material cybersecurity breach of the Corporation's information security systems or those of a third-party service provider 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 Developments

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 available to customers 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.

Further, the implementation of new information technology systems into the business, including those impacting utility operations and customer billing systems, carries risk that any such system will not operate as expected. Failure to maintain, upgrade, replace or properly implement such new information technology systems could result in increased risk of a cybersecurity incident and have an adverse effect on operational efficiency, revenue or reputation (see "Cybersecurity and Information and Operations Technology" above).

Weather Variability and Seasonality

Electricity consumption varies significantly in response to seasonal weather changes which have been and will continue to be impacted by climate change (see "Climate Change" on page 26). 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. Hydroelectric generation is sensitive to rainfall levels and unexpected variations in seasonal rainfall levels can negatively impact operations.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of natural gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities are typically highest in the first and fourth quarters. 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. The absence or the discontinuance of key regulatory mechanisms could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates, consultations, and other approvals from various levels of government, regulators, government agencies and/or other third parties. There is no assurance that: (i) such 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 U.S. 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 and Alberta. 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, including as a result of the exclusion of related costs from customer rates and other 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 such 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 a third party. Some of these permits require approvals 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.

Certain jointly owned facilities and portions of TEP's transmission lines are located on tribal lands pursuant to leases, land easements and other rights-of-way that are effective for specified time periods. The inability to receive future approvals for continued access to the facilities and land 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, any of which could have a Material Adverse Effect.

General Economic Conditions

Fluctuations in general economic conditions, inflation, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors may lower energy demand and reduce sales and reduced capital spending, particularly to the extent that related customer and Rate Base growth are impacted. A severe and prolonged economic downturn could also impair customers' ability to pay their bills in a timely manner. Each of these factors could lead to the impairment of goodwill or other long-term assets, and could have a Material Adverse Effect. Further, the impact of macroeconomic factors, including, but not limited to, international relations and geopolitical events, could cause weaker economic conditions or increase the volatility of the equity capital markets, which could impact the business and financial condition of the Corporation or adversely impact the Corporation's share price.

Commodity Price Volatility

Purchased power and gas, 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; and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 35).

There is no assurance that current regulator-approved mechanisms or strategies will continue to exist in the future. Additionally, despite these mechanisms and strategies, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and sales growth, which 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 and is not being generated by the Corporation's utilities. 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 result in a loss and/or increase in the cost of purchased power and gas, which could have a Material Adverse Effect. The cost and availability of purchased power and gas may be adversely impacted by factors discussed under "Climate Change" on page 26, "Environmental Regulation" on page 27 and "Commodity Price Volatility" on page 29.

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.

Central Hudson has seen an increase in accounts receivable due to the suspension of collection efforts in response to the COVID-19 Pandemic, as well as higher commodity prices. Central Hudson continues to proactively contact customers regarding past-due balances to advise them of financial assistance available through federal and state programs, and collection efforts are expected to expand in 2023. Under its regulatory framework, Central Hudson can defer uncollectible write-offs that exceed 10 basis points above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. 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 credit risk management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Supply Chain

Domestic and global supply chain issues may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the operation of the Corporation's utilities. Failure to eliminate or manage the constraints in the supply chain may impact the availability of items that are necessary to support operations as well as materials that are required for continued infrastructure growth and could have a 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. While a rising interest environment could result in higher allowed ROEs, such ROE changes tend to lag as a result of regulatory timelines. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes. Although interest costs at the regulated utilities are generally recovered through customer rates, the discontinuance of regulatory mechanisms that permit the flow-through of actual interest costs, the impact of regulatory lag at UNS Energy, and higher finance costs on holding company debt could have a Material Adverse Effect.

Foreign Exchange Exposure

As at December 31, 2022, 67% of the Corporation's assets were located outside Canada and 59% of 2022 revenue was derived from foreign operations. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation’s $22.3 billion five-year Capital Plan for 2023 through 2027 also includes exposure to foreign exchange.

Fortis has limited its U.S. dollar currency exposure through hedging. The Corporation has issued and designated U.S. dollar-denominated long-term debt as an effective hedge of foreign net investments. Fortis has also entered into foreign exchange contracts and cross-currency swaps to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, earnings and cash flow continue to be impacted by exchange rate fluctuations. In addition, there is no assurance that existing hedging strategies will continue to be effective, and therefore a significant, prolonged decrease in the U.S. dollar-to-Canadian dollar exchange rate could have a Material Adverse Effect.

Access to Capital

The Corporation and certain of its subsidiaries have incurred material amounts of indebtedness. 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 fund 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 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, credit ratings, and the environmental, social and governance profile of Fortis and its subsidiaries. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

Fortis is a holding company and, as such, has no revenue-generating operations of its own. The Corporation's subsidiaries are separate legal entities and have no independent obligation to pay dividends to Fortis. Prior to paying dividends to the Corporation, the subsidiaries have financial obligations that must be satisfied, including, among others, their operating expenses and obligations to creditors. Furthermore, the Corporation's utilities are required by regulation to maintain a minimum equity-to-total capital ratio that may restrict their ability to pay dividends to the Corporation or may require the Corporation to contribute capital to such subsidiaries. The future enactment of laws or regulations may prohibit or further restrict the ability of the Corporation's subsidiaries to pay dividends or to repay intercorporate indebtedness. In addition, in the event of a subsidiary's liquidation or reorganization, the Corporation's right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors. As a result, the Corporation's ability to generate cash flow to service its debt obligations is reliant on the ability of its subsidiaries to generate sustained earnings and cash flows and to pay dividends and repay loans.

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 17.

Taxation

Earnings at Fortis and its subsidiaries could be impacted by changes in income tax rates and other tax legislation in Canada, the U.S. and other international jurisdictions. The nature, timing or impact of changes in 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, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods. 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.

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 to insure such assets 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 losses from actual damage, liabilities or business interruption will be fully covered by insurance; (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 in insurance coverage or claims payment could have a Material Adverse Effect. The availability and cost of certain types of insurance may be adversely impacted by the risks described under "Climate Change" on page 26.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of a skilled workforce as well as filling strategic positions. 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 or filling strategic positions within the Corporation or its utilities 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 regulators may not allow full recovery in customer 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. Regulatory deferral mechanisms are in place at many of the Corporation's utilities that permit the flow through in customer rates of certain impacts associated with market fluctuations. Severe and prolonged market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, changes in laws and regulations, as well as changes in existing regulatory treatment of post-retirement benefit costs, may increase plan expenses or require additional plan funding and could have a Material Adverse Effect.

Political Environment

The political environment, at the local, national or global level, may impact energy laws, governmental energy policies or regulatory decisions. For example, political pressure or intervention to address rising energy prices and customer affordability concerns may impact regulatory decisions, as well as the period over which the Corporation's utilities recover allowed costs.

The business is further exposed to risks associated with international relations and geopolitical events. Political, economic or social instability or events, trade disputes, increased tariffs, changes in laws or the imposition of onerous regulations applicable to existing operations, currency restrictions, and the impacts of changes in political leadership could lead to an increase in commodity prices, impact the availability and cost of energy or generally affect global economic conditions, any of which could have a Material Adverse Effect (see "Environmental Regulation" at page 27 and "General Economic Conditions" at page 29).

Reputation, Relationships and Stakeholder Activism

There can be no assurance that internal processes, controls or audits will ensure compliance with the Corporation's internal policies, including its Code of Conduct, or anti-bribery and anti-corruption laws. Employees, affiliates, independent contractors or agents may violate such policies and laws, which may potentially lead to reputational damage, in addition to potential fines, penalties or litigation, any of which could have a Material Adverse Effect.

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 of Major Capital Projects, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development. See "Required Approvals" and "Indigenous Land Claims" at page 29.

External stakeholders are increasingly challenging companies regarding climate change, sustainability, diversity, returns (including ROEs and ROAs), 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 manage or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings

Legal, administrative and other 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

Critical Accounting Estimates

General

The preparation of the 2022 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, 2022, Fortis recognized regulatory assets of $4.0 billion (2021 - $3.6 billion) and regulatory liabilities of $3.9 billion (2021 - $3.2 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

Years ended December 31 *($ millions, except as indicated)*	Defined Benefit Pension Plans **2022**	2021	OPEB Plans **2022**	2021
Funded status: [1]				
Benefit obligation [2]	**(3,063)**	(3,922)	**(582)**	(747)
Plan assets	**3,079**	3,722	**389**	440
	16	(200)	**(193)**	(307)
Net benefit cost [2]	**19**	64	**26**	35
Key assumptions: *(weighted average %)*				
Discount rate: [3]				
During the year	**2.97**	2.60	**2.97**	2.60
As at December 31	**5.27**	3.00	**5.36**	2.97
Expected long-term rate of return on plan assets [4]	**5.87**	5.40	**5.00**	4.88
Rate of compensation increase	**3.33**	3.30	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.48**	4.49

(1) *Periodic actuarial valuations determine funding contributions for the pension plans and U.S. 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 2023 rate is 6.17% and is assumed to decrease over the next 12 years to the ultimate rate of 4.48% in 2034 and thereafter*

Sensitivity Analysis Year ended December 31, 2022 *($ millions)*	**Rate of Return 1% change** Increase	Decrease	**Discount Rate 1% change** Increase	Decrease	**Health Care Costs Trend Rate 1% change** Increase	Decrease
Defined benefit pension plans:						
Net benefit cost	**(33)**	**27**	**(35)**	**62**	**n/a**	**n/a**
Projected benefit obligation	**17**	**(49)**	**(337)**	**401**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(5)**	**5**	**(12)**	**12**	**17**	**(13)**
Accumulated benefit obligation	**—**	**—**	**(70)**	**85**	**64**	**(57)**

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.

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, 2022, Fortis recognized property, plant and equipment and intangible assets of $43.2 billion (2021 - $39.2 billion) representing 67% of total assets (2021 - 68%). Depreciation and amortization of these assets totalled $1.6 billion for 2022 (2021 - $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 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, 2022, this regulatory liability was $1.3 billion (2021 - $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, 2022, Fortis recognized goodwill of $12.5 billion (2021 - $11.7 billion), representing 19% of total assets (2021 - 20%). The increase in goodwill was due to the impact of foreign exchange associated with the translation of U.S. 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 performed, 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.

Income Tax
As at December 31, 2022, deferred income tax liabilities, current income tax payable included in accounts payable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $4.1 billion, $88 million, $1.9 billion and $1.4 billion, respectively (2021 - $3.6 billion, $31 million, $1.8 billion and $1.3 billion, respectively). Income tax expense was $289 million in 2022 (2021 - $234 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 and liabilities reflect temporary differences between the tax and accounting basis of assets and 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 income tax expense or recovery recognized under U.S. GAAP and reflected in customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or 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.

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, British Columbia and Alberta). The Corporation's 2018 to 2022 taxation years are still open for audit in Canadian jurisdictions, and its 2018 to 2022 taxation years are still open for audit in U.S. jurisdictions. The impact of such income tax compliance examinations could be material to the Corporation's financial statements (see "Business Risks - Taxation" on page 31).

In August 2022, the IRA was passed into U.S. law. The legislation will be funded, in part, by the introduction of a new 15% corporate alternative minimum income tax, effective for tax years beginning after December 31, 2022. While this tax is expected to be applicable to Fortis, the Corporation does not currently expect it to have a material impact on its financial results, Operating Cash Flow or credit ratings.

In November 2022, the Department of Finance Canada released revised draft legislation which included a proposal on interest deductibility. It is unknown when the legislation may be enacted. In addition, the 2021 Canadian federal budget included proposed changes in relation to international taxation. There has been no significant update on this proposal, and it is unknown when draft legislation may be available. Changes in tax legislation could affect the results of operations, financial condition and cash flows of the Corporation as discussed under “Business Risks - Taxation” on page 31. Fortis will continue to assess the impacts as more details on the tax proposals become available.

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.

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 - Legal, Administrative and Other Proceedings" on page 32, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 26 in the 2022 Annual Financial Statements.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2022, the carrying value of long-term debt, including the current portion, was $28.6 billion (2021 - $25.5 billion) compared to an estimated fair value of $25.8 billion (2021 - $28.8 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, 2022, unrealized losses of $84 million (2021 - $20 million) were recognized as regulatory assets and unrealized gains of $224 million (2021 - $52 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. In 2022, unrealized gains of $34 million (2021 - $21 million) were recognized in revenue.

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 $114 million and terms of one to three years expiring at varying dates through January 2025. 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. In 2022, unrealized losses of $22 million (2021 - unrealized gains of $17 million) were recognized in other income, net.

Foreign exchange contracts
The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through May 2024 and have a combined notional amount of $352 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. In 2022, unrealized losses of $9 million (2021 - $11 million) were recognized in other income, net.

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 US$450 million, were terminated in September 2022 with the issuance of US$600 million senior notes and realized gains of $52 million (US$39 million) were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

Cross-Currency interest rate swaps

In May 2022, the Corporation entered into cross-currency interest rate swaps with a 7-year term to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR rates. In 2022, unrealized losses of $17 million were recorded in other comprehensive income.

Other investments

UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. These investments are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2022, unrealized losses of $11 million (2021 - unrealized gains of $5 million) were recognized in other income, net.

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, 2022				
Assets [(2)]				
Energy contracts subject to regulatory deferral	**—**	**304**	**—**	**304**
Energy contracts not subject to regulatory deferral	**—**	**49**	**—**	**49**
Other investments	**150**	**—**	**—**	**150**
	150	**353**	**—**	**503**
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	**—**	**(164)**	**—**	**(164)**
Energy contracts not subject to regulatory deferral	**—**	**(8)**	**—**	**(8)**
Foreign exchange contracts, total return and cross-currency interest rate swaps	**—**	**(26)**	**—**	**(26)**
	—	**(198)**	**—**	**(198)**
As at December 31, 2021				
Assets [(2)]				
Energy contracts subject to regulatory deferral	—	78	—	78
Energy contracts not subject to regulatory deferral	—	16	—	16
Foreign exchange contracts, total return and interest rate swaps	23	2	—	25
Other investments	137	—	—	137
	160	96	—	256
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	—	(46)	—	(46)
Energy contracts not subject to regulatory deferral	—	(3)	—	(3)
	—	(49)	—	(49)

(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 cash and cash equivalents, accounts receivable and other current assets or other assets*

(3) *Included in accounts payable and other current liabilities or other liabilities*

Derivative Volumes

As at December 31	2022	2021
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**586**	509
Electricity power purchase contracts *(GWh)*	**224**	731
Gas swap contracts *(PJ)*	**185**	151
Gas supply contract premiums *(PJ)*	**148**	144
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,886**	1,886
Gas swap contracts *(PJ)*	**34**	29

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

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2022	2021	2020
Revenue	**11,043**	9,448	8,935
Net earnings	**1,514**	1,405	1,389
Common Equity Earnings	**1,330**	1,231	1,209
EPS: *($)*			
Basic	**2.78**	2.61	2.60
Diluted	**2.78**	2.61	2.60
Total assets	**64,252**	57,659	55,481
Long-term debt (excluding current portion)	**25,931**	23,707	23,113
Dividends declared: *($)*			
Per common share	**2.200**	2.080	1.965
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G	**1.0983**	1.0983	1.0983
Series H [1]	**0.4588**	0.4588	0.5003
Series I [2]	**0.9157**	0.3926	0.4987
Series J	**1.1875**	1.1875	1.1875
Series K	**0.9823**	0.9823	0.9823
Series M	**0.9783**	0.9783	0.9783

(1) *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*
(2) *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield*

2022/2021

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 3, "Operating Results" on page 9, and "Financial Position" on page 16.

2021/2020

The increase in revenue was due primarily to: (i) higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) new customer rates, effective January 1, 2021 and higher wholesale sales at TEP; and (iv) higher retail electricity sales, primarily in Western Canada and the Caribbean, partially offset by lower sales in Arizona due to unfavourable weather. The increase in revenue was partially offset by an unfavourable foreign exchange impact of $345 million and a $40 million favourable base ROE adjustment recognized at ITC in 2020 as a result of the May 2020 FERC decision.

Common Equity Earnings increased by $22 million compared to 2020. Growth in Common Equity Earnings was tempered by the unfavourable impact of foreign exchange of $48 million, and significant one-time items recognized in 2020 of $14 million. The significant items in 2020 included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform. These impacts were partially offset by unrealized mark-to-market gains of $12 million in 2021 on natural gas derivatives at Aitken Creek.

Excluding the impact of the above noted items, the Corporation delivered higher earnings of $72 million reflecting: (i) Rate Base growth; (ii) higher earnings in Arizona primarily due to new customer rates at TEP effective January 1, 2021, partially offset by lower sales due to unfavourable weather and higher operating costs; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) higher sales at FortisAlberta associated with favourable weather, partially offset by a higher effective income tax rate. This growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Aitken Creek due to realized losses on natural gas contracts.

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 DRIP.

The increase in total assets was due to capital expenditures in 2021 as well as an increase in employee future benefit balances, driven by higher discount rates, partially offset by unfavourable foreign exchange on the translation of U.S. dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales

(GWh, except as indicated)	**2022**	2021	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,264**	2,206	58
Wholesale Electricity	**1,247**	1,749	(502)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity	**1,158**	1,203	(45)
Gas *(PJ)*	**8**	6	2
FortisBC Energy *(PJ)*	**75**	74	1
FortisAlberta	**4,200**	4,147	53
FortisBC Electric	**967**	927	40
Other Electric	**2,443**	2,449	(6)
Non-Regulated			
Energy Infrastructure	**83**	13	70

The decrease in electricity sales was driven by UNS Energy due to lower wholesale electricity sales, partially offset by higher retail electricity sales due to favourable weather and customer growth. The decrease was partially offset by higher electricity sales in: (i) Fortis Belize, due to higher hydroelectric production associated with rainfall levels; and (ii) FortisAlberta, due to higher load from industrial customers and higher average consumption by residential customers.

The increase in gas sales was driven by Central Hudson due to higher average consumption by commercial and industrial customers.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2022**	2021	Variance	**2022**	2021	Variance
Regulated Utilities						
ITC	**500**	418	82	**126**	103	23
UNS Energy	**716**	540	176	**45**	33	12
Central Hudson	**396**	283	113	**37**	39	(2)
FortisBC Energy	**725**	592	133	**84**	78	6
FortisAlberta	**169**	156	13	**34**	23	11
FortisBC Electric	**136**	133	3	**14**	14	—
Other Electric	**448**	401	47	**40**	29	11
Non-regulated						
Energy Infrastructure	**78**	60	18	**49**	40	9
Corporate and Other	**—**	—	—	**(59)**	(31)	(28)
Total	**3,168**	2,583	585	**370**	328	42
Weighted average number of common shares outstanding *(# millions)*				**481.1**	473.7	7.4
Basic EPS *($)*				**0.77**	0.69	0.08

The increase in revenue was due primarily to: (i) higher flow-through costs in customer rates, driven by higher commodity prices; (ii) Rate Base growth; (iii) higher wholesale and transmission revenue, as well as retail electricity sales at UNS Energy; and (iv) favourable foreign exchange of $106 million.

The increase in Common Equity Earnings was driven by: (i) Rate Base growth; (ii) higher retail electricity sales and transmission revenue at UNS Energy; (iii) higher earnings from the energy infrastructure segment driven by hydroelectric production in Belize, as well as the favourable impact of market conditions at Aitken Creek; and (iv) the timing of expenses at FortisAlberta. The translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate and lower stock based compensation costs also contributed to results with these impacts exceeding the related losses associated with hedging activities. The increase in earnings was partially offset by higher corporate costs, reflecting higher finance costs and a lower income tax recovery, as well as lower earnings at Central Hudson, reflecting the finalization of the company's rate application in late 2021 with retroactive application to July 1, 2021.

The increase in basic EPS reflects higher Common Equity Earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	**2022**	2021	Variance
Cash and cash equivalents, beginning of period	**395**	225	170
Cash from (used in):			
Operating activities	**869**	717	152
Investing activities	**(1,152)**	(985)	(167)
Financing activities	**103**	174	(71)
Effect of exchange rate changes on cash and cash equivalents	**(6)**	—	(6)
Cash and cash equivalents, end of period	**209**	131	78

Operating Activities

Operating Cash Flow increased due to: (i) higher cash earnings, reflecting Rate Base growth, as well as higher retail electricity sales and transmission revenue in Arizona; (ii) favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates, and (iii) the higher U.S.-to-Canadian dollar exchange rate. The increase was partially offset by the timing of inventory purchases at UNS Energy.

Investing Activities

The variance reflects higher capital expenditures in accordance with the Corporation's 2022 Capital Plan.

Financing Activities

See "Cash Flow Summary" on page 18.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2022	**3,168**	**370**	**0.77**	**0.77**
September 30, 2022	**2,553**	**326**	**0.68**	**0.68**
June 30, 2022	**2,487**	**284**	**0.59**	**0.59**
March 31, 2022	**2,835**	**350**	**0.74**	**0.74**
December 31, 2021	2,583	328	0.69	0.69
September 30, 2021	2,196	295	0.63	0.62
June 30, 2021	2,130	253	0.54	0.54
March 31, 2021	2,539	355	0.76	0.76

Generally, within each calendar year, quarterly results fluctuate 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 U.S. 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 significant temperature fluctuations from seasonal norms; (iii) the timing and significance of any regulatory decisions; (iv) changes in the U.S.-to-Canadian dollar exchange rate; (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 2022/December 2021

See "Fourth Quarter Results" on page 38.

September 2022/September 2021

Common Equity Earnings increased by $31 million and basic EPS increased by $0.05 in comparison to the third quarter of 2021 due to: (i) Rate Base growth, mainly at ITC; (ii) higher retail electricity sales, transmission revenue and earnings associated with the Oso Grande generating facility in Arizona; (iii) higher earnings from the energy infrastructure segment mainly due to mark-to-market accounting of natural gas derivatives and higher hydroelectric production in Belize; and (iv) the impact of new customer rates and the timing of operating costs at Central Hudson.

Growth was tempered by the timing of expenses in Alberta and a favourable adjustment recognized in 2021 related to interest rate swaps at ITC. Results for the third quarter of 2022 were also impacted by significant items at ITC, including costs associated with the suspension of the Lake Erie Connector project, and the revaluation of deferred income tax assets due to a reduction in the corporate income tax rate in the state of Iowa. The impact of mark-to-market losses associated with hedging activities was more than offset by lower stock-based compensation costs and the translation of U.S. dollar-denominated subsidiary earnings at the higher U.S.-to-Canadian dollar foreign exchange rate. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

June 2022/June 2021

Common Equity Earnings increased by $31 million and basic EPS increased by $0.05 in comparison to the second quarter of 2021 due to: (i) Rate Base growth; (ii) higher earnings from the energy infrastructure segment, largely reflecting favourable changes in the mark-to-market accounting of natural gas derivatives at Aitken Creek; and (iii) a higher U.S.-to-Canadian dollar foreign exchange rate. Growth was partially offset by losses on investments that support retirement benefits at UNS Energy and ITC, reflecting market conditions, and the timing of quarterly earnings from Arizona and Alberta. In comparison to the second quarter of 2021, results from UNS Energy were tempered, as expected, by the timing of earnings related to the Oso Grande generating facility, and earnings from FortisAlberta were lower due to the timing of operating expenses. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

March 2022/March 2021

Common Equity Earnings decreased by $5 million and basic EPS decreased by $0.02 in comparison to the first quarter of 2021 due to higher unrealized losses of $14 million on the mark-to-market accounting of natural gas derivatives at Aitken Creek. Excluding this impact, the Corporation delivered earnings growth driven by Rate Base growth at ITC and the western Canadian utilities, and higher sales in the Caribbean. Growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Central Hudson mainly due to the costs of implementing a new CIS.

Earnings in Arizona were broadly consistent with the first quarter of 2021. The impact of higher electricity sales and lower planned generation maintenance costs was offset by the timing of earnings related to the Oso Grande generating facility, as expected. Losses on retirement investments also unfavourably impacted earnings at UNS Energy in the quarter.

The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

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 2022 or 2021.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $37 million in 2022 (2021 - $38 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2022, accounts receivable included $7 million due from Belize Electricity (2021 - $22 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2022, there were no inter-segment loans outstanding (2021 - $126 million). Interest charged on inter-segment loans was not material in 2022 and 2021.

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 U.S. securities laws. As of December 31, 2022, 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 U.S. securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2022.

Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's Board, 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, 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, 2022, 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, 2022, the Corporation's ICFR was effective.

During the year ended December 31, 2022, 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

Fortis continues to enhance shareholder value through the execution of its Capital Plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. While energy price volatility, global supply chain constraints and persistent inflation are issues of potential concern that continue to evolve, the Corporation does not currently expect there to be a material impact on its operations or financial results in 2023.

Fortis is executing on the transition to a cleaner energy future and is on track to achieve its corporate-wide targets to reduce GHG emissions by 50% by 2030 and 75% by 2035. Upon achieving this target, 99% of the Corporation's assets will support energy delivery and renewable, carbon-free generation. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to decarbonize over the long-term, while preserving customer reliability and affordability.

The Corporation's $22.3 billion five-year Capital Plan is expected to increase midyear Rate Base from $34.1 billion in 2022 to $46.1 billion by 2027, translating into a five-year CAGR of 6.2%.

Beyond the five-year Capital Plan, additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with the IRA and the MISO LRTP; climate adaptation and grid resiliency investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2027. This dividend growth guidance will also provide flexibility to fund more capital with internally-generated funds and is premised on the assumptions and material factors listed under "Forward-Looking Information".

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: forecast capital expenditures for 2023-2027, including cleaner energy investments; forecast Rate Base and Rate Base growth for 2023 and through 2027; targeted annual dividend growth through 2027; the expectation that Fortis is well-positioned to capitalize on evolving industry opportunities, including additional investment opportunities beyond the Capital Plan; the expectation that volatility in energy prices, global supply chain constraints and persistent inflation will not have a material impact on operations or financial results in 2023 or the 2023-2027 capital plan; the 2030 GHG emissions reduction target; the 2035 GHG emissions reduction target and projected asset mix; the expectation to achieve the 2030 and 2035 GHG emissions reduction targets without the use of carbon offsets; the 2050 net-zero direct GHG emissions target and how that target is expected to be achieved; TEP's IRP and the expectation to exit coal by 2032; the expected timing, outcome and impact of regulatory proceedings and decisions; the expected or potential funding sources for operating expenses, interest costs and capital expenditures; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on the Corporation's ability to pay dividends in the foreseeable future; the 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 2023; the expected uses of proceeds from debt financings; the targeted capital structure; the nature, timing, benefits and expected costs of certain capital projects, including ITC's transmission projects associated with the MISO LRTP, renewable generation projects at UNS Energy, the Vail-to-Tortolita Transmission Project, the Tilbury LNG Storage Expansion, the AMI Project; the Eagle Mountain Woodfibre Gas Line Project, the Tilbury 1B Project, the Okanagan Capacity Upgrade, the Wataynikaneyap Transmission Power Project, and additional opportunities beyond the capital plan, including investments associated with the IRA, the MISO LRTP, TEP's IRP, climate adaptation and grid resiliency, and renewable gas solutions and LNG infrastructure in British Columbia; the expectation that the introduction of a corporate alternative minimum income tax will not have a material impact on financial results, Operating Cash Flow or credit ratings; the expectation that long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2027; and the expectation that the dividend growth guidance will provide flexibility to fund more capital internally.

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 volatility in energy prices, global supply chain constraints and persistent inflation; 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; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition 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 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 2023 include, but are not limited to: uncertainty regarding changes in utility regulation, including the outcome of regulatory proceedings at the Corporation's utilities; the physical risks associated with the provision of electric and gas service, which are exacerbated by the impacts of climate change; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with cybersecurity and information and operations technology; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with commodity price volatility and supply of purchased power; and risks related to general economic conditions, including inflation, interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 9, 2023. 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

2022 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2022

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-U.S. GAAP Financial Measures" on page 14

Adjusted Payout Ratio: dividends per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 14

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

ACC: Arizona Corporation Commission

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

BECOL: Belize Electric Company Limited, an indirect wholly owned subsidiary of Fortis (now known as Fortis Belize)

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

Board: Board of Directors of the Corporation

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 U.S. dollar to Canadian dollar exchange rate

Capital Expenditures: cash outlay for additions to property, plant and equipment and intangible assets as shown in the Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. See "Non-US GAAP Financial Measures" on page 14

Capital Plan: forecast Capital Expenditures. Represents a non-U.S. GAAP financial measure calculated in the same manner as Capital Expenditures

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2022) 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

CIS: customer information system

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS: cost of service

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

CRMP: Cybersecurity Risk Management Program

DBRS Morningstar: DBRS Limited

D.C. Circuit Court: U.S. Court of Appeals for the District of Columbia Circuit

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPRI: Electric Power Research Institute

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

Fortis Belize: Fortis Belize Limited, an indirect wholly owned subsidiary of Fortis (formerly known as BECOL)

Four Corners: Four Corners Generating Station, Units 4 and 5

FX: foreign exchange associated with the translation of U.S. dollar-denominated amounts. Foreign exchange is calculated by applying the change in the U.S.-to-Canadian dollar FX rates to the prior period U.S. dollar balance.

GCOC: generic cost of capital

GHG: greenhouse gas

GWh: gigawatt hour(s)

ICFR: internal control over financial reporting

ICAT: Iowa Coalition for Affordable Transmission

IRA: Inflation Reduction Act of 2022

IRP: Integrated Resource Plan

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

LNG: liquefied natural gas

LRTP: Long Range Transmission Plan

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, 2022

MISO: Midcontinent Independent System Operator, Inc.

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

MW: megawatt(s)

Navajo: Navajo Generating Station

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

Non-U.S. GAAP Financial Measures: financial measures that do not have a standardized meaning prescribed by U.S. 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)

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

REA: Rural Electrification Association

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

RTO: regional transmission organization

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

SOFR: Secured Overnight Financing Rate

TCFD: Task Force for Climate-Related Financial Disclosures

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

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

TSX: Toronto Stock Exchange

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

U.S.: United States of America

U.S. GAAP: accounting principles generally accepted in the U.S.

Waneta Expansion: Waneta Expansion hydroelectric generation facility

Wataynikaneyap Partnership: Wataynikaneyap Power Limited Partnership

Consolidated Financial Statements

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2022 and 2021

Consolidated Financial Statements

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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, 2022, 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, 2022, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2022 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, 2022. Deloitte LLP issued an unqualified opinion for both audits.

February 9, 2023

/s/ David G. Hutchens

David G. Hutchens

President and Chief Executive Officer, Fortis Inc.
St. John's, Canada

/s/ Jocelyn H. Perry

Jocelyn H. Perry

Executive Vice President, Chief Financial Officer, Fortis Inc.

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2022, 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, 2022, 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 9, 2023, 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 primarily 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 terminal 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 terminal 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 terminal growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the terminal growth rate by:
  - Assessing the methodology used in management's determination of the terminal 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 9, 2023

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, 2022, 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, 2022, 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, 2022, of the Corporation and our report dated February 9, 2023, 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 9, 2023

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)		**2022**		2021
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**209**	$	131
Accounts receivable and other current assets (Note 6)		**2,339**		1,511
Prepaid expenses		**146**		116
Inventories (Note 7)		**661**		478
Regulatory assets (Note 8)		**914**		492
Total current assets		**4,269**		2,728
Other assets (Note 9)		**1,213**		955
Regulatory assets (Note 8)		**3,095**		3,097
Property, plant and equipment, net (Note 10)		**41,663**		37,816
Intangible assets, net (Note 11)		**1,548**		1,343
Goodwill (Note 12)		**12,464**		11,720
Total assets	**$**	**64,252**	$	57,659
LIABILITIES AND EQUITY				
Current liabilities				
Short-term borrowings (Note 14)	**$**	**253**	$	247
Accounts payable and other current liabilities (Note 13)		**3,288**		2,570
Regulatory liabilities (Note 8)		**595**		357
Current installments of long-term debt (Note 14)		**2,481**		1,628
Total current liabilities		**6,617**		4,802
Regulatory liabilities (Note 8)		**3,320**		2,865
Deferred income taxes (Note 22)		**4,060**		3,627
Long-term debt (Note 14)		**25,931**		23,707
Finance leases (Note 15)		**336**		333
Other liabilities (Note 16)		**1,146**		1,409
Total liabilities		**41,410**		36,743
Commitments and contingencies (Note 26)				
Equity				
Common shares [(1)]		**14,656**		14,237
Preference shares (Note 18)		**1,623**		1,623
Additional paid-in capital		**10**		10
Accumulated other comprehensive income (loss) (Note 19)		**1,008**		(40)
Retained earnings		**3,733**		3,458
Shareholders' equity		**21,030**		19,288
Non-controlling interests		**1,812**		1,628
Total equity		**22,842**		20,916
Total liabilities and equity	**$**	**64,252**	$	57,659

[(1)] No par value. Unlimited authorized shares. 482.2 million and 474.8 million issued and outstanding as at December 31, 2022 and 2021, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel
Jo Mark Zurel,
Director

/s/ Maura J. Clark
Maura J. Clark,
Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2022**	2021
Revenue (Note 5)	**$ 11,043**	$ 9,448
Expenses		
Energy supply costs	**3,952**	2,951
Operating expenses	**2,683**	2,523
Depreciation and amortization	**1,668**	1,505
Total expenses	**8,303**	6,979
Operating income	**2,740**	2,469
Other income, net (Note 21)	**165**	173
Finance charges	**1,102**	1,003
Earnings before income tax expense	**1,803**	1,639
Income tax expense (Note 22)	**289**	234
Net earnings	**$ 1,514**	$ 1,405
Net earnings attributable to:		
Non-controlling interests	**$ 120**	$ 111
Preference equity shareholders	**64**	63
Common equity shareholders	**1,330**	1,231
	$ 1,514	$ 1,405
Earnings per common share (Note 17)		
Basic	**$ 2.78**	$ 2.61
Diluted	**$ 2.78**	$ 2.61

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)	**2022**	2021
Net earnings	**$ 1,514**	$ 1,405
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $15 million and $(2) million, respectively	**1,100**	(93)
Other, net of income tax expense of $21 million and $3 million, respectively	**73**	8
	1,173	(85)
Comprehensive income	**$ 2,687**	$ 1,320
Comprehensive income attributable to:		
Non-controlling interests	**$ 245**	$ 100
Preference equity shareholders	**64**	63
Common equity shareholders	**2,378**	1,157
	$ 2,687	$ 1,320

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the year ended December 31 (in millions of Canadian dollars)	**2022**	2021
Operating activities		
Net earnings	**$ 1,514**	$ 1,405
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,460**	1,313
Amortization - intangible assets	**145**	136
Amortization - other	**63**	56
Deferred income tax expense (Note 22)	**182**	147
Equity component, allowance for funds used during construction (Note 21)	**(78)**	(77)
Other	**105**	75
Change in long-term regulatory assets and liabilities	**162**	(4)
Change in working capital (Note 24)	**(479)**	(144)
Cash from operating activities	**3,074**	2,907
Investing activities		
Additions to property, plant and equipment	**(3,587)**	(3,189)
Additions to intangible assets	**(278)**	(197)
Contributions in aid of construction	**111**	93
Contributions to equity-accounted investees	**(100)**	—
Other	**(205)**	(195)
Cash used in investing activities	**(4,059)**	(3,488)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,067**	1,324
Repayments of long-term debt and finance leases	**(1,526)**	(634)
Borrowings under committed credit facilities	**6,651**	5,082
Repayments under committed credit facilities	**(6,381)**	(4,749)
Net change in short-term borrowings	**(21)**	115
Issue of common shares, net of costs, and dividends reinvested	**53**	60
Dividends		
Common shares, net of dividends reinvested	**(673)**	(608)
Preference shares	**(64)**	(63)
Subsidiary dividends paid to non-controlling interests	**(66)**	(58)
Other	**(5)**	(18)
Cash from financing activities	**1,035**	451
Effect of exchange rate changes on cash and cash equivalents	**28**	12
Change in cash and cash equivalents	**78**	(118)
Cash and cash equivalents, beginning of year	**131**	249
Cash and cash equivalents, end of year	**$ 209**	$ 131

Supplementary Cash Flow Information (Note 24)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(# millions)*	**Common Shares**	**Preference Shares** (Note 18)	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** (Note 19)	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2021	**474.8**	**$ 14,237**	**$ 1,623**	**$ 10**	**$ (40)**	**$ 3,458**	**$ 1,628**	**$ 20,916**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,394**	**120**	**1,514**
Other comprehensive income	**—**	**—**	**—**	**—**	**1,048**	**—**	**125**	**1,173**
Common shares issued	**7.4**	**419**	**—**	**(2)**	**—**	**—**	**—**	**417**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(66)**	**(66)**
Dividends declared on common shares ($2.20 per share)	**—**	**—**	**—**	**—**	**—**	**(1,055)**	**—**	**(1,055)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(64)**	**—**	**(64)**
Other	**—**	**—**	**—**	**2**	**—**	**—**	**5**	**7**
As at December 31, 2022	**482.2**	**$ 14,656**	**$ 1,623**	**$ 10**	**$ 1,008**	**$ 3,733**	**$ 1,812**	**$ 22,842**
As at December 31, 2020	466.8	$ 13,819	$ 1,623	$ 11	$ 34	$ 3,210	$ 1,587	$ 20,284
Net earnings	—	—	—	—	—	1,294	111	1,405
Other comprehensive loss	—	—	—	—	(74)	—	(11)	(85)
Common shares issued	8.0	418	—	(2)	—	—	—	416
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(58)	(58)
Dividends declared on common shares ($2.08 per share)	—	—	—	—	—	(983)	—	(983)
Dividends on preference shares	—	—	—	—	—	(63)	—	(63)
Other	—	—	—	1	—	—	(1)	—
As at December 31, 2021	474.8	$ 14,237	$ 1,623	$ 10	$ (40)	$ 3,458	$ 1,628	$ 20,916

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 a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma. ITC also has electric transmission system assets under construction in Wisconsin.

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 3,328 megawatts ("MW"), including 68 MW of solar capacity and 250 MW of wind 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 primarily includes 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 90 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 166 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a generating capacity of 86 MW, including 84 MW of diesel-powered generating capacity and 2 MW of solar capacity. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

1. DESCRIPTION OF BUSINESS (cont'd)

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 Fortis Belize Limited (formerly known as Belize Electric Company Limited). 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.

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 and non-regulated holding company expenses.

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 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).

2. REGULATION (cont'd)

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE [1] (%) 2022	2021	Significant Features
ITC [2]	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.77	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC") [4]	53.0	**9.15**	9.15	COS regulation Historical test year
	FERC	[5]	**9.79**	9.79	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson [6]	New York State Public Service Commission ("PSC")	49.0	**9.00**	9.00	COS regulation Future test year
FortisBC Energy [7]	British Columbia Utilities Commission ("BCUC")	38.5	**8.75**	8.75	COS regulation with formula components and incentives [8]
FortisBC Electric [7]	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**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [11]	Utility Regulation and Competition Office	N/A	**6.25-8.25**	6.00-8.00	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. See "Significant Regulatory Developments" below
(3) Annual true-up collected or refunded in rates within a two-year period
(4) Approved ROE of 9.15% with a 0.20% return on the fair value increment. A general rate application requesting new rates effective September 1, 2023 is ongoing. See "Significant Regulatory Developments" below
(5) The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio
(6) Effective July 1, 2021 Central Hudson's approved common equity component of capital structure was 50%, declining by 1% annually to 48% in the third rate year
(7) A generic cost of capital ("GCOC") proceeding is ongoing. See "Significant Developments" below
(8) Formula and incentives have been set through 2024
(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 expired as of December 31, 2022. See "Significant Regulatory Developments" below
(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

Significant Regulatory Developments

ITC

ITC Midwest Capital Structure Complaint: In May 2022, the Iowa Coalition for Affordable Transmission ("ICAT") filed a complaint with FERC under Section 206 of the Federal Power Act requesting that ITC Midwest's common equity component of capital structure be reduced from 60% to 53%. ICAT alleged that ITC Midwest does not meet FERC's three-part test for authorizing the use of the utility's actual capital structure for rate-making purposes. In November 2022, FERC issued an order denying the complaint, and in December 2022, ICAT filed a request for rehearing with FERC. As at December 31, 2022, ITC Midwest has not recorded a regulatory liability related to the complaint.

2. REGULATION (cont'd)

MISO Base ROE: In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the Midcontinent Independent System Operator, Inc. ("MISO") region, including ITC. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect. The court has remanded the matter to FERC for further process, the timing and outcome of which is unknown.

Transmission Incentives: In 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding is unknown.

UNS Energy

TEP General Rate Application: In June 2022, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2023 using a December 31, 2021 test year. The application reflects a US$136 million net increase in non-fuel and fuel-related revenue, as well as proposals to eliminate certain adjustor mechanisms, and modify an existing adjustor to provide more timely recovery of clean energy investments. The timing and outcome of this proceeding is unknown.

Central Hudson

Customer Information System ("CIS") Implementation: In December 2022, the PSC released a report into the deployment by Central Hudson of its new CIS. The PSC also issued an Order to Commence Proceeding and Show Cause, which directed Central Hudson to explain why the PSC should not pursue civil or administrative penalties or initiate a proceeding to review the prudence of the CIS implementation costs. Central Hudson was also required to submit a plan to eliminate bi-monthly bill estimates and to evaluate the customer impacts of such a change. Central Hudson's response was filed in January 2023. The timing and outcome of this proceeding is unknown.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In 2021, the BCUC initiated a proceeding including a review of the common equity component of capital structure and the allowed ROE. FortisBC filed a final argument with the BCUC in December 2022 and the proceeding remains ongoing, with a decision expected in the second quarter of 2023.

FortisAlberta

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for Alberta regulated utilities for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. In March 2022, the AUC issued a decision extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. The GCOC proceeding for 2024 and beyond remains ongoing, and a decision is expected in the third quarter of 2023.

2023 COS Application: In July 2022, the AUC issued a decision largely accepting the forecast requested in FortisAlberta's COS application. The associated compliance filing, including the updated 2023 revenue requirement, was approved by the AUC in December 2022.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta is participating in this proceeding and a decision from the AUC is expected in 2023.

Rural Electrification Association ("REA") Cost Recovery: In 2021, the AUC determined that costs attributable to REAs, approximating $10 million annually, can no longer be recovered from FortisAlberta's rate payers, effective January 1, 2023. FortisAlberta filed an appeal with the Alberta Court of Appeal, asserting that the AUC erred in preventing the company from recovering these costs from its own rate payers to the extent that such costs cannot be recovered directly from REAs. The appeal was heard in December 2022, and a decision from the Court is expected in first quarter of 2023.

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 ("U.S. 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. 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 U.S. GAAP for rate-regulated entities.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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 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 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 removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual removal costs are netted when incurred.

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 2022 totalled $45 million (2021 - $39 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 21). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

Excluding UNS Energy and Central Hudson, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulators, 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 and ranged from 0.5% to 39.8% for 2022 (2021 - 0.9% to 39.8%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2022 (2021 – 2.6%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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

	2022		2021	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**31**	5-80	32
Gas	**18-95**	**39**	18-95	38
Transmission				
Electric	**20-90**	**41**	20-90	42
Gas	**10-85**	**35**	10-85	35
Generation	**5-95**	**22**	5-95	23
Other	**3-80**	**11**	3-70	13

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 2022 (2021 – 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.

	2022		2021	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**5**	3-15	4
Land, transmission and water rights	**34-90**	**54**	34-90	55
Other	**10-100**	**11**	10-100	11

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 total undiscounted cash flows expected to be generated by the asset may be below carrying value. 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 performed, 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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 U.S. 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. In addition, 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 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 Alberta Electric System Operator. 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 probable.

Revenue excludes sales and municipal taxes collected from customers.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Revenue Recognition (cont'd)

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

Effective January 1, 2022, stock options have been excluded from the Corporation's long-term incentive mix. Compensation expense related to stock options granted in 2021 or prior were measured at the grant date using the Black-Scholes fair value option-pricing model with each grant amortized to compensation expense 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 and PSUs, represent cash-settled awards whereas RSU's represent cash or share-settled awards, depending on settlement elections and the 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, 2022 was $54.65 (2021 - $61.08). 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 U.S. 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, 2022 was US$1.00=CA$1.36 (2021 – US$1.00=CA$1.26).

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$1.30 for 2022 (2021 - US$1.00=CA$1.25).

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 U.S. 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.

The Corporation's earnings from, and net investments in, foreign subsidiaries and certain equity-accounted investments are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through U.S. 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Derivatives and Hedging (cont'd)

Presentation of Derivatives

The fair value of derivatives is 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 Fortis Belize are not subject to income tax.

Differences between the income tax expense or recovery recognized under U.S. 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).

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 $5.3 billion as at December 31, 2022 (2021 - $4.1 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with U.S. 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 Accounting Standards Updates ("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 2022 or 2021.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $37 million in 2022 (2021 - $38 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2022, accounts receivable included $7 million due from Belize Electricity (2021 - $22 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2022, there were no inter-segment loans outstanding (2021 - $126 million). Interest charged on inter-segment loans was not material in 2022 and 2021.

4. SEGMENTED INFORMATION (cont'd)

	Regulated								Non-Regulated			
($ 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**
Year ended December 31, 2022												
Revenue	1,906	2,758	1,325	2,084	680	487	1,652	**10,892**	**151**	**—**	**—**	**11,043**
Energy supply costs	—	1,213	525	1,055	—	141	1,013	**3,947**	**5**	**—**	**—**	**3,952**
Operating expenses	481	691	571	364	166	133	217	**2,623**	**40**	**20**	**—**	**2,683**
Depreciation and amortization	385	365	104	298	243	67	187	**1,649**	**17**	**2**	**—**	**1,668**
Operating income	1,040	489	125	367	271	146	235	**2,673**	**89**	**(22)**	**—**	**2,740**
Other income, net	48	22	59	22	5	6	14	**176**	**1**	**(12)**	**—**	**165**
Finance charges	349	127	53	146	110	76	75	**936**	**—**	**166**	**—**	**1,102**
Income tax expense	184	56	28	39	15	12	22	**356**	**18**	**(85)**	**—**	**289**
Net earnings	555	328	103	204	151	64	152	**1,557**	**72**	**(115)**	**—**	**1,514**
Non-controlling interests	101	—	—	1	—	—	18	**120**	**—**	**—**	**—**	**120**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**64**	**—**	**64**
Net earnings attributable to common equity shareholders	454	328	103	203	151	64	134	**1,437**	**72**	**(179)**	**—**	**1,330**
Additions to property, plant and equipment and intangible assets	1,212	709	293	589	510	130	393	**3,836**	**29**	**—**	**—**	**3,865**
As at December 31, 2022												
Goodwill	8,318	1,873	612	913	228	235	258	**12,437**	**27**	**—**	**—**	**12,464**
Total assets	23,478	12,678	5,131	8,875	5,547	2,596	4,916	**63,221**	**884**	**159**	**(12)**	**64,252**
Year ended December 31, 2021												
Revenue	1,691	2,334	1,000	1,715	644	468	1,498	9,350	98	—	—	9,448
Energy supply costs	—	919	285	713	—	136	895	2,948	3	—	—	2,951
Operating expenses	466	648	498	355	157	128	201	2,453	33	37	—	2,523
Depreciation and amortization	291	345	91	281	231	65	181	1,485	17	3	—	1,505
Operating income	934	422	126	366	256	139	221	2,464	45	(40)	—	2,469
Other income, net	42	41	34	12	2	5	5	141	1	31	—	173
Finance charges	300	120	46	144	106	73	71	860	—	143	—	1,003
Income tax expense	156	51	21	48	11	12	21	320	8	(94)	—	234
Net earnings	520	292	93	186	141	59	134	1,425	38	(58)	—	1,405
Non-controlling interests	94	—	—	1	—	—	16	111	—	—	—	111
Preference share dividends	—	—	—	—	—	—	—	—	—	63	—	63
Net earnings attributable to common equity shareholders	426	292	93	185	141	59	118	1,314	38	(121)	—	1,231
Additions to property, plant and equipment and intangible assets	1,046	710	291	475	389	134	321	3,366	20	—	—	3,386
As at December 31, 2021												
Goodwill	7,755	1,746	570	913	228	235	246	11,693	27	—	—	11,720
Total assets	21,020	11,126	4,356	8,135	5,201	2,540	4,357	56,735	777	295	(148)	57,659

5. REVENUE

($ millions)	2022	2021
Electric and gas revenue		
United States		
ITC	**1,911**	1,694
UNS Energy	**2,498**	2,071
Central Hudson	**1,307**	962
Canada		
FortisBC Energy	**2,080**	1,645
FortisAlberta	**655**	622
FortisBC Electric	**429**	404
Newfoundland Power	**722**	701
Maritime Electric	**234**	223
FortisOntario	**220**	211
Caribbean		
Caribbean Utilities	**349**	248
FortisTCI	**98**	89
Total electric and gas revenue	**10,503**	8,870
Other services revenue [1]	**409**	382
Revenue from contracts with customers	**10,912**	9,252
Alternative revenue	**(28)**	(18)
Other revenue	**159**	214
Total revenue	**11,043**	9,448

[1] *Includes $266 million and $260 million from regulated operations for 2022 and 2021, respectively*

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. This mechanism is in place until the expiry of the current multi-year rate plan in 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, respectively, 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, as well as regulatory deferrals at FortisBC Energy and FortisBC Electric reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2022**	2021
Trade accounts receivable	**930**	621
Unbilled accounts receivable	**887**	701
Allowance for credit losses	**(58)**	(53)
	1,759	1,269
Other [(1)]	**580**	242
	2,339	1,511

[(1)] *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 25)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2022**	2021
Balance, beginning of year	**(53)**	(64)
Credit loss expensed	**(27)**	(7)
Credit loss deferral	**(6)**	—
Write-offs, net of recoveries	**30**	18
Foreign exchange	**(2)**	—
Balance, end of year	**(58)**	(53)

See Note 25 for disclosure on the Corporation's credit risk.

7. INVENTORIES

($ millions)	**2022**	2021
Materials and supplies	**394**	318
Gas and fuel in storage	**235**	131
Coal inventory	**32**	29
	661	478

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2022**	2021
Regulatory assets		
Deferred income taxes (Note 3)	**1,874**	1,806
Rate stabilization and related accounts [(1)]	**557**	339
Deferred energy management costs [(2)]	**445**	384
Employee future benefits (Notes 3 and 23)	**207**	388
Deferred lease costs [(3)]	**132**	127
Manufactured gas plant site remediation deferral (Note 16)	**97**	96
Deferred restoration costs [(4)]	**91**	17
Derivatives (Notes 3 and 25)	**84**	20
Generation early retirement costs [(5)]	**78**	48
Other regulatory assets [(6)]	**444**	364
Total regulatory assets	**4,009**	3,589
Less: Current portion	**(914)**	(492)
Long-term regulatory assets	**3,095**	3,097

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

($ millions)	2022	2021
Regulatory liabilities		
Deferred income taxes (Note 3)	**1,364**	1,289
Future cost of removal (Note 3)	**1,306**	1,217
Employee future benefits (Notes 3 and 23)	**306**	196
Rate stabilization and related accounts [1]	**297**	116
Derivatives (Notes 3 and 25)	**224**	52
Renewable energy surcharge [7]	**126**	107
Energy efficiency liability [8]	**89**	83
Other regulatory liabilities [6]	**203**	162
Total regulatory liabilities	**3,915**	3,222
Less: Current portion	**(595)**	(357)
Long-term regulatory liabilities	**3,320**	2,865

(1) ***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).

(2) ***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 one to 10 years.

(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) ***Deferred Restoration Costs:*** Incremental costs incurred at Central Hudson and Maritime Electric associated with restoration activities due to significant weather events. Incremental costs incurred in excess of that collected in customer rates at Central Hudson are recovered through rate stabilization accounts. The form and recovery period for Maritime Electric will be determined by the regulator.

(5) ***Generation Early Retirement Costs:*** Includes costs at TEP associated with the retirement of the Navajo Generating Station ("Navajo") and Sundt Generating Facility Units 1 and 2 in 2019 and the San Juan Generating Station ("San Juan") in 2022, as approved for recovery by its regulator.

(6) ***Other Regulatory Assets and Liabilities:*** Comprised of regulatory assets and liabilities individually less than $40 million.

(7) ***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.

(8) ***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.

Regulatory assets not earning a return: (i) totalled $1,980 million and $1,727 million as at December 31, 2022 and 2021, 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

($ millions)	2022	2021
Employee future benefits (Note 23)	**274**	259
Equity investments [(1)]	**201**	92
Supplemental Executive Retirement Plan ("SERP")	**155**	165
RECs (Note 8)	**142**	112
Derivatives	**118**	40
Other investments	**115**	86
Operating leases (Note 15)	**43**	40
Deferred compensation plan	**40**	42
Other	**125**	119
	1,213	955

(1) *Includes investments in Belize Electricity and Wataynikaneyap Partnership*

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 life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 25).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Cost	Accumulated Depreciation	Net Book Value
2022			
Distribution			
Electric	**13,650**	**(3,715)**	**9,935**
Gas	**6,396**	**(1,626)**	**4,770**
Transmission			
Electric	**19,056**	**(4,074)**	**14,982**
Gas	**2,600**	**(800)**	**1,800**
Generation	**7,173**	**(2,679)**	**4,494**
Other	**4,803**	**(1,610)**	**3,193**
Assets under construction	**2,094**	**—**	**2,094**
Land	**395**	**—**	**395**
	56,167	**(14,504)**	**41,663**
2021			
Distribution			
Electric	12,321	(3,359)	8,962
Gas	5,838	(1,504)	4,334
Transmission			
Electric	17,104	(3,610)	13,494
Gas	2,453	(756)	1,697
Generation	7,014	(2,691)	4,323
Other	4,362	(1,454)	2,908
Assets under construction	1,759	—	1,759
Land	339	—	339
	51,190	(13,374)	37,816

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

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 assets associated with natural gas storage at Aitken Creek.

As at December 31, 2022, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy.

The cost of PPE under finance lease as at December 31, 2022 was $323 million (2021 - $323 million) and related accumulated depreciation was $117 million (2021 - $113 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, 2022, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	Various	**1,333**	**(428)**	**905**
Springerville Common Facilities	86.0	**544**	**(294)**	**250**
Springerville Coal Handling Facilities	83.0	**281**	**(133)**	**148**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**264**	**(119)**	**145**
Gila River Common Facilities	50.0	**118**	**(43)**	**75**
Luna Energy Facility ("Luna")	33.3	**77**	**—**	**77**
		2,617	**(1,017)**	**1,600**

11. INTANGIBLE ASSETS

($ millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
2022			
Computer software	**985**	**(497)**	**488**
Land, transmission and water rights	**1,064**	**(171)**	**893**
Other	**135**	**(78)**	**57**
Assets under construction	**110**	**—**	**110**
	2,294	**(746)**	**1,548**
2021			
Computer software	952	(518)	434
Land, transmission and water rights	941	(154)	787
Other	113	(69)	44
Assets under construction	78	—	78
	2,084	(741)	1,343

Included in the cost of land, transmission and water rights as at December 31, 2022 was $117 million (2021 - $137 million) not subject to amortization. Amortization expense was $145 million for 2022 (2021 - $136 million). Amortization is estimated to average approximately $90 million for each of the next five years.

12. GOODWILL

($ millions)	2022	2021
Balance, beginning of year	**11,720**	11,792
Foreign currency translation impacts [1]	**744**	(72)
Balance, end of year	**12,464**	11,720

[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 U.S. dollar*

No goodwill impairment was recognized by the Corporation in 2022 or 2021.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	2022	2021
Trade accounts payable	**886**	774
Gas and fuel cost payable	**512**	269
Customer and other deposits	**401**	288
Accrued taxes other than income taxes	**282**	238
Dividends payable	**278**	259
Employee compensation and benefits payable	**270**	283
Interest payable	**254**	218
Derivatives (Note 25)	**127**	43
Income taxes payable	**88**	31
Employee future benefits (Note 23)	**28**	26
Manufactured gas plant site remediation (Note 16)	**17**	13
Other	**145**	128
	3,288	2,570

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2022**	2021
ITC			
Secured U.S. First Mortgage Bonds -			
4.22% weighted average fixed rate (2021 - 4.31%)	2024-2055	**3,344**	2,736
Secured U.S. Senior Notes -			
3.83% weighted average fixed rate (2021 - 3.90%)	2040-2055	**1,186**	1,011
Unsecured U.S. Senior Notes -			
3.98% weighted average fixed rate (2021 - 3.61%)	2023-2043	**4,541**	4,108
Unsecured U.S. Shareholder Note -			
6.00% fixed rate (2021 - 6.00%)	2028	**270**	252
UNS Energy			
Unsecured U.S. Tax-Exempt Bond - 4.00% weighted			
average fixed rate (2021 - 4.34%)	2029	**123**	359
Unsecured U.S. Fixed Rate Notes -			
3.58% weighted average fixed rate (2021 - 3.62%)	2023-2052	**3,450**	2,780
Central Hudson			
Unsecured U.S. Promissory Notes - 4.14% weighted			
average fixed and variable rate (2021 - 3.83%)	2024-2060	**1,526**	1,177
FortisBC Energy			
Unsecured Debentures -			
4.61% weighted average fixed rate (2021 - 4.61%)	2026-2052	**3,295**	3,145
FortisAlberta			
Unsecured Debentures -			
4.49% weighted average fixed rate (2021 - 4.49%)	2024-2052	**2,485**	2,360
FortisBC Electric			
Secured Debentures -			
8.80% fixed rate (2021 - 8.80%)	2023	**25**	25
Unsecured Debentures -			
4.70% weighted average fixed rate (2021 - 4.77%)	2035-2052	**860**	760
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
5.26% weighted average fixed rate (2021 - 5.61%)	2026-2060	**666**	627
Secured First Mortgage Bonds -			
5.31% weighted average fixed rate (2021 - 5.31%)	2025-2061	**260**	260
Unsecured Senior Notes -			
4.45% weighted average fixed rate (2021 - 4.45%)	2041-2048	**152**	152
Unsecured U.S. Senior Loan Notes and Bonds -			
4.71% weighted average fixed and variable rate (2021 - 4.36%)	2023-2052	**745**	609
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes -			
3.82% weighted average fixed rate (2021 - 3.82%)	2023-2044	**2,691**	2,509
Unsecured Debentures -			
6.51% fixed rate (2021 - 6.51%)	2039	**200**	200
Unsecured Senior Notes -			
3.31% weighted average fixed rate (2021 - 2.52%)	2028-2029	**1,000**	1,000
Long-term classification of credit facility borrowings		**1,657**	1,305
Fair value adjustment - ITC acquisition		**102**	107
Total long-term debt (Note 25)		**28,578**	25,482
Less: Deferred financing costs and debt discounts		**(166)**	(147)
Less: Current installments of long-term debt		**(2,481)**	(1,628)
		25,931	23,707

14. LONG-TERM DEBT (cont'd)

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 restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances in 2022	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount** *($ millions)*	**Use of Proceeds**
ITC						
Secured first mortgage bonds	January	2.93	2052	**US**	**150**	(1) (2) (3) (4)
Secured senior notes	May	3.05	2052	**US**	**75**	(1) (3) (4)
Unsecured senior notes	September	4.95 (5)	2027	**US**	**600**	(1) (4) (6)
Secured first mortgage bonds	October	3.87	2027	**US**	**75**	(2)
Secured first mortgage bonds	October	4.53	2052	**US**	**75**	(2)
UNS Energy						
Unsecured senior notes	February	3.25	2032	**US**	**325**	(4) (6)
Central Hudson						
Unsecured senior notes	January	2.37	2027	**US**	**50**	(4) (6)
Unsecured senior notes	January	2.59	2029	**US**	**60**	(4) (6)
Unsecured senior notes	September	5.07	2032	**US**	**100**	(1) (4)
Unsecured senior notes	September	5.42	2052	**US**	**10**	(1) (4)
FortisBC Energy						
Unsecured debentures	November	4.67	2052		**150**	(2)
FortisAlberta						
Senior unsecured debentures	May	4.62	2052		**125**	(1)
FortisBC Electric						
Unsecured debentures	March	4.16	2052		**100**	(1)
Newfoundland Power						
First mortgage sinking fund bonds	April	4.20	2052		**75**	(1) (4) (6)
Caribbean Utilities						
Unsecured senior notes	November	5.88	2052	**US**	**80**	(1) (3)
Fortis						
Unsecured senior notes	May	4.43 (7)	2029		**500**	(4) (8)

(1) Repay short-term and/or credit facility borrowings
(2) Fund or refinance, in part or in full, a portfolio of new and/or existing eligible green projects
(3) Fund capital expenditures
(4) General corporate purposes
(5) ITC entered into interest rate swaps which reduced the effective interest rate to 3.54%. See Note 25 to the 2022 Annual Financial Statements
(6) Repay maturing long-term debt
(7) The Corporation entered into cross-currency interest rate swaps to effectively convert the debt into US$391 million with an interest rate of 4.34% (Note 25)
(8) Fund the June 2022 redemption of the Corporation's $500 million, 2.85% senior unsecured notes due December 2023

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.

($ millions)	**Total**
2023	2,481
2024	1,434
2025	518
2026	2,434
2027	1,977
Thereafter	19,734
	28,578

14. LONG-TERM DEBT (cont'd)

In November 2022, 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, 2022, $2.0 billion remained available under the short-form base shelf prospectus.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**2022**	2021
Total credit facilities	3,795	2,055	**5,850**	4,846
Credit facilities utilized:				
Short-term borrowings [(1)]	(253)	—	**(253)**	(247)
Long-term debt (including current portion) [(2)]	(922)	(735)	**(1,657)**	(1,305)
Letters of credit outstanding	(76)	(52)	**(128)**	(115)
Credit facilities unutilized	2,544	1,268	**3,812**	3,179

(1) *The weighted average interest rate was approximately 4.9% (2021 - 0.6%).*
(2) *The weighted average interest rate was approximately 5.1% (2021 - 0.9%). The current portion was $1,376 million (2021 - $888 million).*

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.6 billion of the total credit facilities are committed facilities with maturities ranging from 2023 through 2027.

In 2022, Central Hudson increased its available credit facilities from US$230 million to US$320 million.

In May 2022, the Corporation amended its unsecured $1.3 billion revolving term committed credit facility agreement to extend the maturity to July 2027, and to establish a sustainability-linked loan structure based on the Corporation's achievement of targets for diversity on the Board of Directors and Scope 1 greenhouse gas emissions for 2022 through 2025. Maximum potential annual margin pricing adjustments are +/- 5 basis points and +/- 1 basis point for drawn and undrawn funds, respectively.

Also in May 2022, the Corporation entered into an unsecured US$500 million non-revolving term credit facility. The facility has an initial one-year term and is repayable at any time without penalty.

Consolidated credit facilities of approximately $5.9 billion as at December 31, 2022 are itemized below.

($ millions)		**Amount**	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [(1)]	**US**	**900**	2024
UNS Energy	**US**	**375**	2026
Central Hudson	**US**	**250**	2025
FortisBC Energy		**700**	2027
FortisAlberta		**250**	2027
FortisBC Electric		**150**	2027
Other Electric		**255**	[(2)]
Other Electric	**US**	**83**	2025
Corporate and Other		**1,350**	[(3)]
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**70**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2024
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**	2023
Corporate and Other			
Unsecured non-revolving facility	**US**	**500**	2023
Unsecured non-revolving facility		**27**	n/a

(1) *ITC also has a US$400 million commercial paper program, under which US$134 million was outstanding as at December 31, 2022 (2021 - US$155 million), as reported in short-term borrowings.*
(2) *$65 million in 2025, $90 million in 2025 and $100 million in 2027*
(3) *$50 million in 2024 and $1.3 billion in 2027*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 25 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 33 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2022**	2021
Operating leases		
Other assets	**43**	40
Accounts payable and other current liabilities	**(9)**	(8)
Other liabilities	**(34)**	(32)
Finance leases [(1)]		
Regulatory assets	**132**	127
PPE, net	**206**	210
Accounts payable and other current liabilities	**(2)**	(4)
Finance leases	**(336)**	(333)

(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.*

The components of lease expense were as follows.

($ millions)	**2022**	2021
Operating lease cost	**9**	8
Finance lease cost:		
Amortization	**1**	2
Interest	**33**	32
Variable lease cost	**21**	19
Total lease cost	**64**	61

As at December 31, 2022, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2023	10	35	**45**
2024	9	35	**44**
2025	6	35	**41**
2026	5	35	**40**
2027	3	36	**39**
Thereafter	19	1,001	**1,020**
	52	1,177	**1,229**
Less: Imputed interest	(9)	(839)	**(848)**
Total lease obligations	43	338	**381**
Less: Current installments	(9)	(2)	**(11)**
	34	336	**370**

15. LEASES (cont'd)

Supplemental lease information follows.

($ millions, except as indicated)	**2022**	2021
Weighted average remaining lease term *(years)*		
Operating leases	**9**	10
Finance leases	**33**	34
Weighted average discount rate *(%)*		
Operating leases	**4.1**	3.8
Finance leases	**5.0**	5.1
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**(8)**	(8)
Financing cash flows used for finance leases	**(1)**	(2)

16. OTHER LIABILITIES

($ millions)	**2022**	2021
Employee future benefits (Note 23)	**423**	740
AROs (Note 3)	**174**	184
Customer and other deposits	**107**	99
Manufactured gas plant site remediation [(1)]	**95**	83
Stock-based compensation plans (Note 20)	**79**	96
Derivatives (Note 25)	**72**	7
Deferred compensation plan (Note 9)	**48**	50
Mine reclamation obligations [(2)]	**39**	44
Operating leases (Note 15)	**34**	32
Retail energy contract [(3)]	**33**	40
Other	**42**	34
	1,146	1,409

[(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, 2022, an obligation of $100 million was recognized, including a current portion of $5 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 $54 million. The present value of the estimated future liability is shown in the table above.

[(3)] In 2020, 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 which is being amortized to revenue over the life of the agreement.

17. EARNINGS PER COMMON SHARE

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

	2022			2021		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,330**	**478.6**	**2.78**	1,231	470.9	2.61
Potential dilutive effect of stock options	**—**	**0.4**	**—**	—	0.5	—
Diluted EPS	**1,330**	**479.0**	**2.78**	1,231	471.4	2.61

18. PREFERENCE SHARES

Authorized

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

Issued and Outstanding First Preference Shares	**2022**		2021	
	Number of Shares *(thousands)*	**Amount** *($ millions)*	Number of Shares *(thousands)*	Amount *($ millions)*
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,665	188
Series I	**2,335**	**57**	2,335	57
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	4.75	1.1875	—	Currently Redeemable	25.00	—
Fixed rate reset [3] [4]						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H	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 [4] [5]						
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) *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.*

(4) *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.*

(5) *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.*

18. PREFERENCE SHARES *(cont'd)*

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.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Opening Balance	Net Change	Ending Balance
2022			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**273**	**1,222**	**1,495**
Hedges of net investments in foreign operations	**(276)**	**(254)**	**(530)**
Income tax (expense) recovery	**(8)**	**15**	**7**
	(11)	**983**	**972**
Other			
Interest rate hedges (Note 25)	**(5)**	**54**	**49**
Unrealized employee future benefits (losses) gains (Note 23)	**(36)**	**30**	**(6)**
Income tax recovery (expense)	**12**	**(19)**	**(7)**
	(29)	**65**	**36**
Accumulated other comprehensive income	**(40)**	**1,048**	**1,008**
2021			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	377	(104)	273
Hedges of net investments in foreign operations	(299)	23	(276)
Income tax expense	(6)	(2)	(8)
	72	(83)	(11)
Other			
Interest rate hedges (Note 25)	(4)	(1)	(5)
Unrealized employee future benefits (losses) gains (Note 23)	(49)	13	(36)
Income tax recovery (expense)	15	(3)	12
	(38)	9	(29)
Accumulated other comprehensive income	34	(74)	(40)

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Effective 2022, the Corporation no longer grants stock options. Existing options to purchase common shares of the Corporation are exercisable for a period of 10 years from the grant date, expire no later than three years after the death or retirement of the optionee, and vest evenly over a four-year period on each anniversary of the grant date.

As at December 31, 2022, the Corporation had 2.3 million (2021 - 2.9 million) stock options outstanding with a weighted average exercise price of $47.72 (2021 - $47.20). The options vested as of December 31, 2022, were 1.5 million (2021 – 1.4 million) with a weighted average exercise price of $44.86 (2021 - $42.76).

In 2022, 1 million stock options were exercised (2021 - 1 million) for cash proceeds of $26 million (2021 - $32 million) and an intrinsic value realized by employees of $9 million (2021 - $11 million).

20. STOCK-BASED COMPENSATION PLANS (cont'd)

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.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**183**	147
Granted	**33**	30
Notional dividends reinvested	**8**	6
End of year	**224**	183

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2022 or 2021.

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 subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant. Beginning with the 2022 PSU grant, the Corporation's Scope 1 carbon reduction performance as compared to the target established at the time of the grant has been included in the payout percentage.

The following table summarizes information related to PSUs.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**1,898**	1,976
Granted	**580**	587
Notional dividends reinvested	**58**	60
Paid out	**(712)**	(697)
Cancelled/forfeited	**(34)**	(28)
End of year	**1,790**	1,898
Additional information *($ millions)*		
Compensation expense recognized	**25**	74
Compensation expense unrecognized [(1)]	**24**	33
Cash payout	**66**	50
Accrued liability as at December 31 [(2)]	**90**	132
Aggregate intrinsic value as at December 31 [(3)]	**114**	165

(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 other liabilities (Notes 13 and 16)
(3) Relates to outstanding PSUs and reflects a weighted average contractual life of one year

20. STOCK-BASED COMPENSATION PLANS (cont'd)

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. Effective January 1, 2020, new RSU issuances 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.

	2022	2021
Number of units *(thousands)*		
Beginning of year	**1,060**	1,048
Granted	**331**	378
Notional dividends reinvested	**29**	32
Paid out	**(410)**	(371)
Cancelled/forfeited	**(33)**	(27)
End of year	**977**	1,060
Additional information *($ millions)*		
Compensation expense recognized	**16**	26
Compensation expense unrecognized [(1)]	**16**	17
Cash payout	**25**	21
Accrued liability as at December 31 [(2)]	**40**	46
Aggregate intrinsic value as at December 31 [(3)]	**56**	63

(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*

21. OTHER INCOME, NET

($ millions)	2022	2021
Non-service component of net periodic benefit cost	**92**	45
Equity component of AFUDC	**78**	77
Interest income	**11**	5
(Loss) gain on derivatives, net	**(17)**	30
(Loss) gain on retirement investments, net	**(18)**	4
Other	**19**	12
	165	173

22. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

($ millions)	**2022**	2021
Gross deferred income tax assets		
Regulatory liabilities	**674**	560
Tax loss and credit carryforwards	**658**	556
Employee future benefits	**161**	169
Other	**160**	91
	1,653	1,376
Valuation allowance	**(32)**	(23)
Net deferred income tax asset	**1,621**	1,353
Gross deferred income tax liabilities		
PPE	**(5,146)**	(4,571)
Regulatory assets	**(388)**	(283)
Intangible assets	**(147)**	(126)
	(5,681)	(4,980)
Net deferred income tax liability	**(4,060)**	(3,627)

Income Tax Expense

($ millions)	**2022**	2021
Canadian		
Earnings before income tax expense	**447**	427
Current income tax	**93**	84
Deferred income tax	**(41)**	(35)
Total Canadian	**52**	49
Foreign		
Earnings before income tax expense	**1,356**	1,212
Current income tax	**14**	3
Deferred income tax	**223**	182
Total Foreign	**237**	185
Income tax expense	**289**	234

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.

22. INCOME TAXES (cont'd)

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

($ millions, except as indicated)	**2022**	2021
Earnings before income tax expense	**1,803**	1,639
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**541**	492
Decrease resulting from:		
Foreign and other statutory rate differentials	**(162)**	(155)
AFUDC	**(18)**	(16)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(74)**	(74)
Items capitalized for accounting purposes but expensed for income tax purposes	**(7)**	(8)
Other	**9**	(5)
Income tax expense	**289**	234
Effective tax rate *(%)*	**16.0**	14.3

Income Tax Carryforwards

($ millions)	Expiring Year	**2022**
Canadian		
Non-capital loss	2028-2042	**393**
Foreign		
Federal and state net operating loss[1]	2023-2042	**3,093**
Other tax credits	2023-2042	**131**
		3,224
Total income tax carryforwards recognized		**3,617**

[1] *Indefinite carryforward for Federal net operating losses, and for states that have adopted the Federal provisions, effective for tax years beginning after December 31, 2017*

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, British Columbia and Alberta). The Corporation's 2018 to 2022 taxation years are still open for audit in Canadian jurisdictions, and its 2018 to 2022 taxation years are still open for audit in United States jurisdictions.

23. 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, 2019 for FortisBC Electric plans (non-unionized employees), Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2020 for the Corporation; December 31, 2021 for FortisBC Energy and the remaining FortisBC Electric plans and December 31, 2022 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.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets *(weighted average %)*	**2022 Target Allocation**	**2022**	2021
Equities	**47**	**48**	48
Fixed income	**46**	**43**	45
Real estate	**6**	**8**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
2022				
Equities	**666**	**1,005**	**—**	**1,671**
Fixed income	**199**	**1,289**	**—**	**1,488**
Real estate	**—**	**—**	**264**	**264**
Private equities	**—**	**—**	**18**	**18**
Cash and other	**5**	**22**	**—**	**27**
	870	**2,316**	**282**	**3,468**
2021				
Equities	749	1,271	—	2,020
Fixed income	219	1,642	—	1,861
Real estate	—	—	235	235
Private equities	—	—	21	21
Cash and other	10	15	—	25
	978	2,928	256	4,162

(1) *See Note 25 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.

($ millions)	**2022**	2021
Balance, beginning of year	**256**	224
Return on plan assets	**28**	32
Foreign currency translation	**3**	—
Purchases, sales and settlements	**(5)**	—
Balance, end of year	**282**	256

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

($ millions)	Defined Benefit Pension Plans 2022	Defined Benefit Pension Plans 2021	OPEB Plans 2022	OPEB Plans 2021
Change in benefit obligation [1]				
Balance, beginning of year	**3,922**	3,995	**747**	789
Service costs	**106**	109	**35**	35
Employee contributions	**18**	18	**3**	2
Interest costs	**114**	98	**21**	19
Benefits paid	**(195)**	(170)	**(29)**	(25)
Actuarial gains	**(1,026)**	(111)	**(225)**	(70)
Past service costs (credits)/plan amendments	**—**	(2)	**1**	—
Foreign currency translation	**124**	(15)	**29**	(3)
Balance, end of year [2]	**3,063**	3,922	**582**	747
Change in value of plan assets				
Balance, beginning of year	**3,722**	3,528	**440**	391
Actual return on plan assets	**(651)**	291	**(77)**	48
Benefits paid	**(187)**	(158)	**(24)**	(21)
Employee contributions	**18**	18	**3**	2
Employer contributions	**54**	55	**19**	22
Foreign currency translation	**123**	(12)	**28**	(2)
Balance, end of year	**3,079**	3,722	**389**	440
Funded status	**16**	(200)	**(193)**	(307)
Balance sheet presentation				
Other assets (Note 9)	**188**	204	**86**	55
Other current liabilities (Note 13)	**(15)**	(13)	**(13)**	(13)
Other liabilities (Note 16)	**(157)**	(391)	**(266)**	(349)
	16	(200)	**(193)**	(307)

(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 $2,818 million as at December 31, 2022 (2021 - $3,586 million).

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2022, the obligation was $978 million compared to plan assets of $790 million (2021 - $2,188 million and $1,799 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, 2022, the obligation was $833 million compared to plan assets of $790 million (2021 - $1,243 million and $1,063 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2022, the obligation was $310 million compared to plan assets of $31 million (2021 - $398 million and $36 million, respectively).

Net Benefit Cost [1]

($ millions)	Defined Benefit Pension Plans 2022	Defined Benefit Pension Plans 2021	OPEB Plans 2022	OPEB Plans 2021
Service costs	**106**	109	**35**	35
Interest costs	**114**	98	**21**	19
Expected return on plan assets	**(194)**	(177)	**(23)**	(19)
Amortization of actuarial losses (gains)	**4**	36	**(10)**	(2)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(1)
Regulatory adjustments	**(10)**	(1)	**4**	3
	19	64	**26**	35

(1) The non-service benefit cost components of net periodic benefit cost are included in other income, net in the consolidated statements of earnings.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

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	
($ millions)	**2022**	2021	**2022**	2021
Unamortized net actuarial losses (gains)	**9**	33	**(11)**	(5)
Unamortized past service costs	**1**	1	**7**	7
Income tax (recovery) expense	**(2)**	(8)	**1**	—
Accumulated other comprehensive income	**8**	26	**(3)**	2
Net actuarial losses (gains)	**103**	260	**(195)**	(81)
Past service credits	**(4)**	(5)	**(4)**	(6)
Other regulatory deferrals	**(6)**	10	**7**	14
	93	265	**(192)**	(73)
Regulatory assets (Note 8)	**207**	376	**—**	12
Regulatory liabilities (Note 8)	**(114)**	(111)	**(192)**	(85)
Net regulatory assets (liabilities)	**93**	265	**(192)**	(73)

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

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Current year net actuarial gains	**(23)**	(10)	**(6)**	(4)
Amortization of actuarial losses	**1**	1	**—**	—
Foreign currency translation	**(2)**	—	**—**	—
Income tax expense	**6**	2	**1**	1
Total recognized in comprehensive income	**(18)**	(7)	**(5)**	(3)
Current year net actuarial gains	**(155)**	(220)	**(118)**	(95)
Past service cost/plan amendments	**—**	—	**1**	—
Amortization of actuarial (losses) gains	**(6)**	(35)	**10**	2
Amortization of past service credits	**1**	2	**1**	2
Foreign currency translation	**4**	(2)	**(6)**	—
Regulatory adjustments	**(16)**	(3)	**(7)**	(4)
Total recognized in regulatory liabilities	**(172)**	(258)	**(119)**	(95)

Significant Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2022**	2021	**2022**	2021
Discount rate during the year [(1)]	**2.97**	2.60	**2.97**	2.60
Discount rate as at December 31	**5.27**	3.00	**5.36**	2.97
Expected long-term rate of return on plan assets [(2)]	**5.87**	5.40	**5.00**	4.88
Rate of compensation increase	**3.33**	3.30	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.48**	4.49

(1) ITC and UNS Energy 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 2023 weighted average health care cost trend rate is 6.17% and is assumed to decrease over the next 12 years to the weighted average ultimate health care cost trend rate of 4.48% in 2034 and thereafter.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments ($ millions)	Defined Benefit Pension Payments	OPEB Payments
2023	$ 177	$ 30
2024	183	32
2025	190	33
2026	197	35
2027	203	35
2028-2032	1,094	191

During 2023, the Corporation expects to contribute $35 million for defined benefit pension plans and $20 million for OPEB plans.

In 2022, the Corporation expensed $47 million (2021 - $44 million) related to defined contribution pension plans.

24. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	2022	2021
Cash paid (received) for		
Interest	**1,057**	986
Income taxes	**79**	(13)
Change in working capital		
Accounts receivable and other current assets	**(479)**	(88)
Prepaid expenses	**(22)**	(15)
Inventories	**(153)**	(56)
Regulatory assets - current portion	**(307)**	(99)
Accounts payable and other current liabilities	**449**	164
Regulatory liabilities - current portion	**33**	(50)
	(479)	(144)
Non-cash investing and financing activities		
Accrued capital expenditures	**411**	432
Common share dividends reinvested	**364**	356
Contributions in aid of construction	**13**	13

25. 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.

Derivatives are recorded 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.

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

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, 2022, unrealized losses of $84 million (2021 - $20 million) were recognized as regulatory assets and unrealized gains of $224 million (2021 - $52 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. In 2022, unrealized gains of $34 million (2021 - $21 million) were recognized in revenue.

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 $114 million and terms of one to three years expiring at varying dates through January 2025. 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. In 2022, unrealized losses of $22 million (2021 - unrealized gains of $17 million) were recognized in other income, net.

Foreign Exchange Contracts
The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through May 2024 and have a combined notional amount of $352 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. In 2022, unrealized losses of $9 million (2021 - $11 million) were recognized in other income, net.

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 US$450 million, were terminated in September 2022 with the issuance of US$600 million senior notes and realized gains of $52 million (US$39 million) were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

Cross-Currency Interest Rate Swaps
In May 2022, the Corporation entered into cross-currency interest rate swaps with a 7-year term to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt (Note 14). The Corporation designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on secured overnight financing rates. In 2022, unrealized losses of $17 million were recorded in other comprehensive income.

Other Investments
UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. These investments are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2022, unrealized losses of $11 million (2021 - unrealized gains of $5 million) were recognized in other income, net.

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Recurring Fair Value Measures

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, 2022				
Assets				
Energy contracts subject to regulatory deferral [2] [3]	**—**	**304**	**—**	**304**
Energy contracts not subject to regulatory deferral [2]	**—**	**49**	**—**	**49**
Other investments [4]	**150**	**—**	**—**	**150**
	150	**353**	**—**	**503**
Liabilities				
Energy contracts subject to regulatory deferral [3] [5]	**—**	**(164)**	**—**	**(164)**
Energy contracts not subject to regulatory deferral [5]	**—**	**(8)**	**—**	**(8)**
Foreign exchange contracts, total return and cross-currency interest rate swaps [5]	**—**	**(26)**	**—**	**(26)**
	—	**(198)**	**—**	**(198)**
As at December 31, 2021				
Assets				
Energy contracts subject to regulatory deferral [2] [3]	—	78	—	78
Energy contracts not subject to regulatory deferral [2]	—	16	—	16
Foreign exchange contracts, total return and interest rate swaps [2]	23	2	—	25
Other investments [4]	137	—	—	137
	160	96	—	256
Liabilities				
Energy contracts subject to regulatory deferral [3] [5]	—	(46)	—	(46)
Energy contracts not subject to regulatory deferral [5]	—	(3)	—	(3)
	—	(49)	—	(49)

(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 cash and cash equivalents and other assets

(5) Included in accounts payable and other current liabilities or other liabilities

Energy Contracts

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.

($ millions)	Gross Amount Recognized In Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
As at December 31, 2022				
Derivative assets	**353**	**54**	**63**	**236**
Derivative liabilities	**(172)**	**(54)**	**—**	**(118)**
As at December 31, 2021				
Derivative assets	94	25	7	62
Derivative liabilities	(49)	(25)	—	(24)

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Volume of Derivative Activity

As at December 31, 2022, 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.

	2022	2021
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**586**	509
Electricity power purchase contracts *(GWh)*	**224**	731
Gas swap contracts *(PJ)*	**185**	151
Gas supply contract premiums *(PJ)*	**148**	144
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,886**	1,886
Gas swap contracts *(PJ)*	**34**	29

[(1)] *GWh means gigawatt hours and PJ means petajoules*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. The customers have investment-grade credit ratings and credit risk is further managed by 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.

Central Hudson has seen an increase in accounts receivable due to the suspension of collection efforts in response to the COVID-19 pandemic, as well as higher commodity prices. Central Hudson continues to proactively contact customers regarding past-due balances to advise them of financial assistance available through federal and state programs, and collection efforts are expected to expand in 2023. Under its regulatory framework, Central Hudson can defer uncollectible write-offs that exceed 10 basis points above the amounts collected in customer rates for future recovery.

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, Central Hudson and FortisBC Energy, 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 $178 million as at December 31, 2022 (2021 - $59 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize Limited and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has limited this exposure through hedging.

As at December 31, 2022, US$2.9 billion (2021 - US$2.2 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.6 billion (2021 - US$10.8 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, 2022, the carrying value of long-term debt, including current portion, was $28.6 billion (2021 - $25.5 billion) compared to an estimated fair value of $25.8 billion (2021 - $28.8 billion).

26. COMMITMENTS AND CONTINGENCIES

As at December 31, 2022, unconditional minimum purchase obligations were as follows.

($ millions)	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Gas and fuel purchase obligations (1)	**5,720**	1,024	516	461	374	328	3,017
Waneta Expansion capacity agreement (2)	**2,472**	54	55	56	58	59	2,190
Renewable PPAs (3)	**1,926**	131	131	131	131	130	1,272
Power purchase obligations (4)	**1,691**	334	253	191	192	113	608
ITC easement agreement (5)	**380**	14	14	14	14	14	310
Debt collection agreement (6)	**106**	3	3	3	3	3	91
Renewable energy credit purchase agreements (7)	**77**	18	14	7	7	6	25
Other (8)	**132**	21	9	20	3	3	76
	12,504	**1,599**	**995**	**883**	**782**	**656**	**7,589**

(1) *FortisBC Energy ($4,804 million):* includes contracts of $2,720 million for the purchase of renewable natural gas expiring in 2044 and contracts of $2,084 million for the purchase of gas, renewable 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, 2022. The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

UNS Energy ($801 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, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2022. 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.

(2) *FortisBC Electric* is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

(3) *TEP and UNS Electric* are party to renewable PPAs, with expiry dates from 2027 through 2051, 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.

(4) *Maritime Electric ($746 million):* includes an energy purchase agreement and transmission capacity contract for 30 MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario ($489 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 ($258 million): includes 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.

UNS Energy ($153 million): an agreement with Salt River Project Agricultural Improvement and Power District to purchase up to 300 MW of capacity, power and ancillary services through 2023. TEP will pay monthly capacity charges and variable power charges.

(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 licenses 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, are collected in customer rates.

(7) UNS Energy and Central Hudson are party to REC 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 AROs and joint-use asset and shared service agreements.

26. COMMITMENTS AND CONTINGENCIES (cont'd)

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. The Wataynikaneyap Partnership has loan agreements in place 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 Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and 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 San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $339 million for Four Corners. As at December 31, 2022, 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 $74 million, for which it has issued a parental guarantee. As at December 31, 2022, there was no obligation under this guarantee.

As at December 31, 2022, FortisBC Holdings Inc. ("FHI") had $142 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 2016, the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In 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.