FORTIS INC.

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.

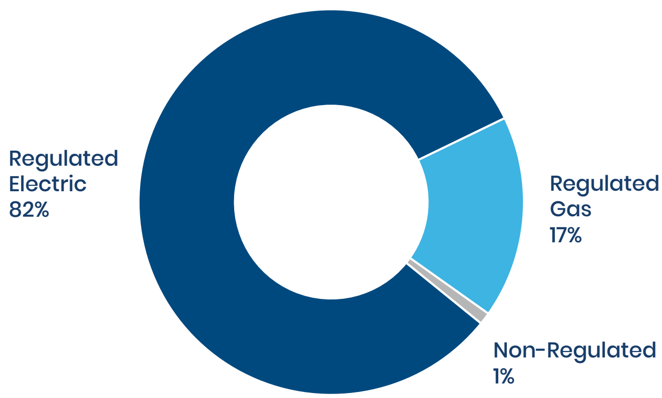
Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.30 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.

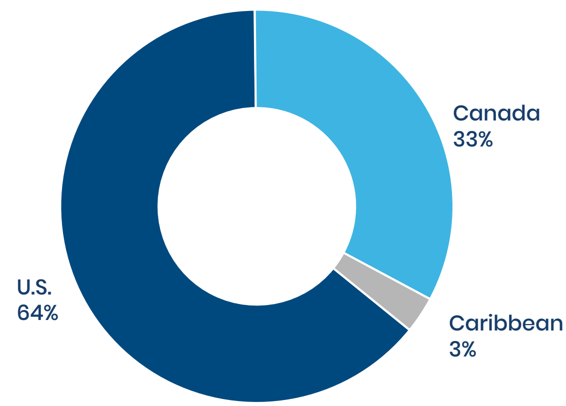
ABOUT FORTIS

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

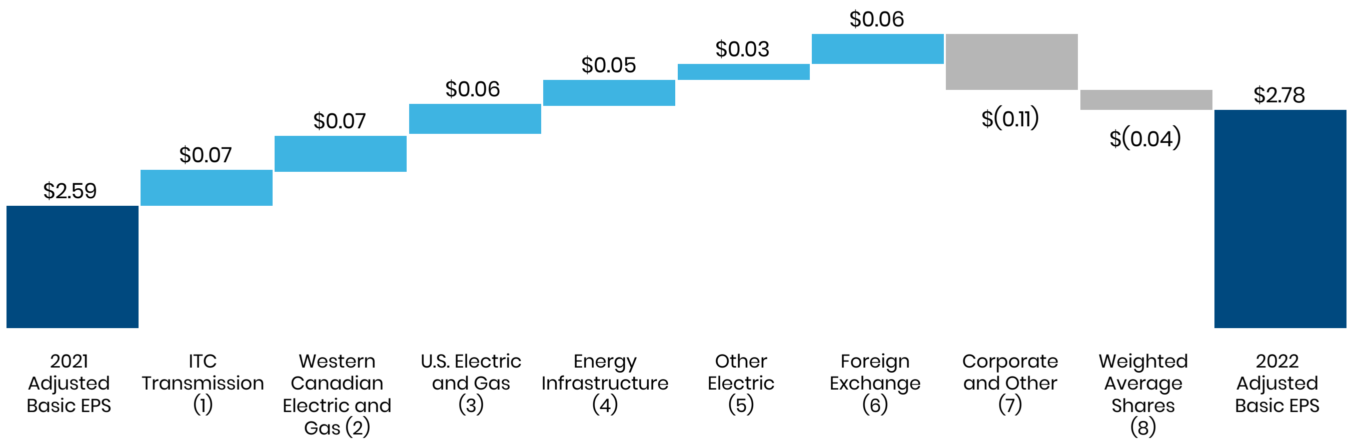
The Corporation reported Common Equity Earnings of $1.3 billion in 2022, or $2.78 per common share, compared to $1.2 billion, or $2.61 per common share in 2021. Our businesses performed well in 2022, delivering approximately 7% annual EPS growth. The increase was primarily driven by Rate Base growth 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

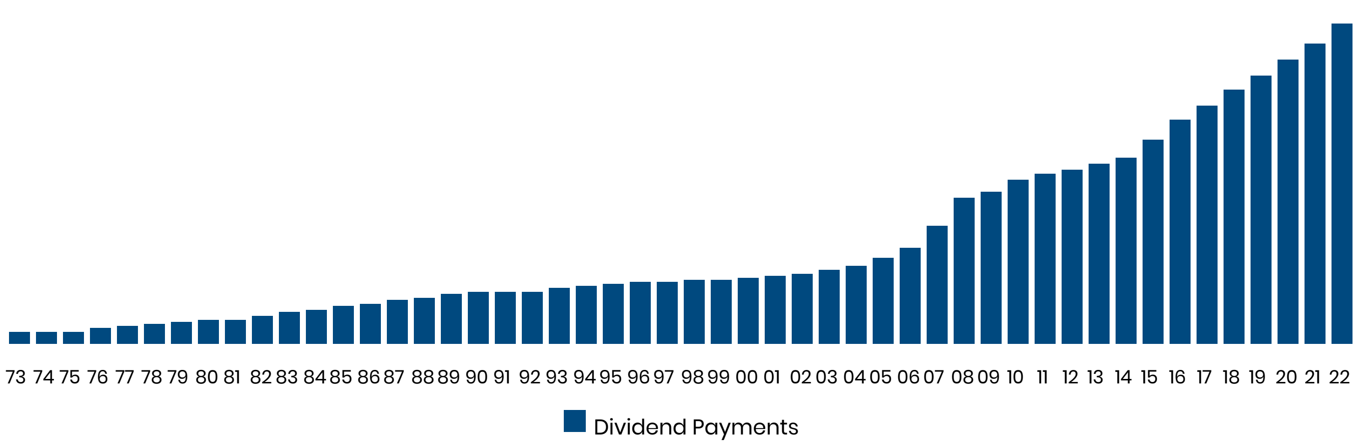
(8) Weighted average shares of 478.6 million in 2022 compared to 470.9 million in 2021

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 49th 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

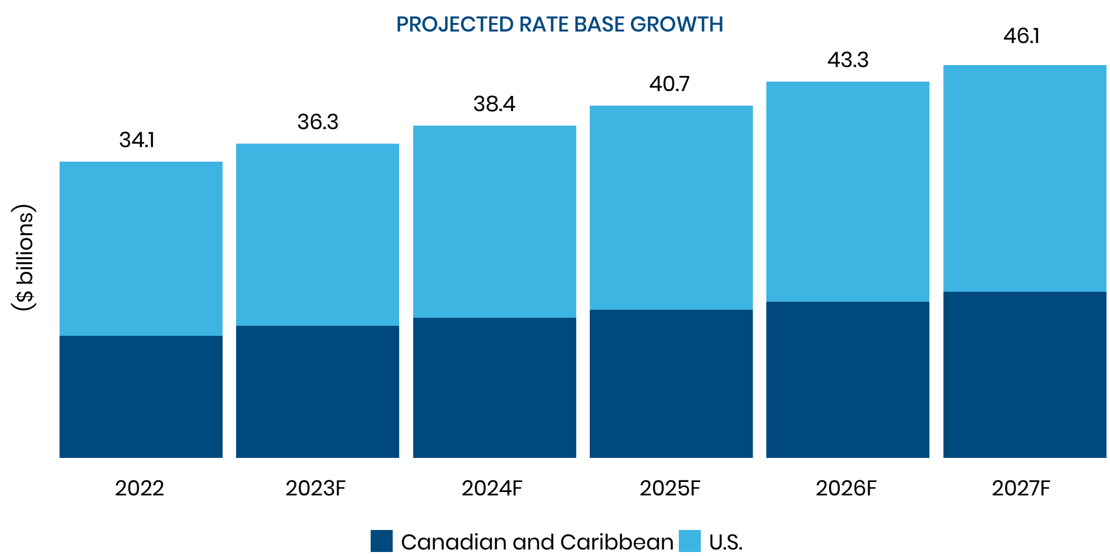
Capital Expenditures were $4.0 billion, consistent with the 2022 Capital Plan and $0.5 billion higher than 2021. The increase over 2021 was primarily due to continued investment in various smaller transmission and distribution projects at the Corporation's regulated utilities, as well as the impact of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

			Variance	
($ millions)	**2022**	2021	FX [1]	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

			Variance	
($ millions)	**2022**	2021	FX	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	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]

($ millions, except as indicated)	Regulated Utilities: 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**

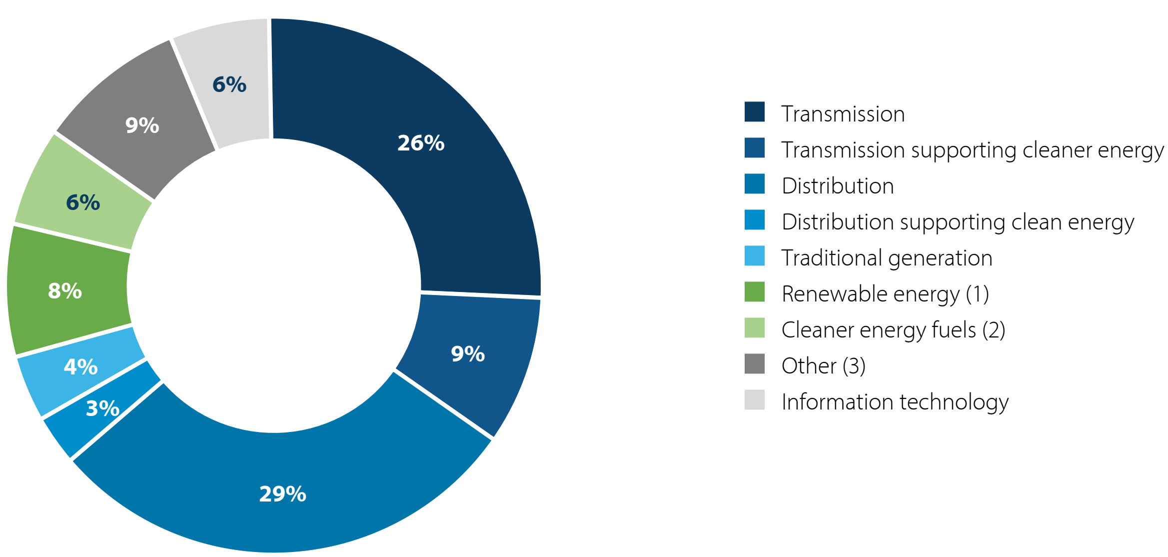
(1) *Capital Plan is a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 14*
(2) *Reflects an assumed U.S.:CAD foreign exchange rate of 1.30. On average, Fortis estimates that a five-cent increase or decrease 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**	**Defined Benefit Pension Plans 2021**	**OPEB Plans 2022**	**OPEB Plans 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**	**Rate of Return 1% change Decrease**	**Discount Rate 1% change Increase**	**Discount Rate 1% change Decrease**	**Health Care Costs Trend Rate 1% change Increase**	**Health Care Costs Trend Rate 1% change 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

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	/s/ Maura J. Clark
Jo Mark Zurel,	**Maura J. Clark,**
Director	**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	2021	OPEB Plans 2022	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	2021	OPEB Plans 2022	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.

Fortis Inc. | Income Statement

TSX:FTS (MI KEY: 4082871; SPCIQ KEY: 875612)

Source: SNL Financial
Period Category: Custom
Period Type: Custom
Reporting Basis: Custom
Sort Order: Custom
Currency: U.S. Dollar (USD)
Magnitude: Thousands (K)

SNL FINANCIAL	2022 FY	2021 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2022	12/31/2021
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.738869	0.790208
Average Exchange Rate	0.768812	0.797827
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD
Operating Revenue ($000)		
Electric Utility Revenue	3,748,727	3,509,639
Gas Distribution Revenue	1,602,204	1,368,272
Electric Revenue	3,748,727	3,509,639
Oil & Natural Gas Revenue	1,602,204	1,368,272
Other Operating Revenue	3,139,059	2,659,954
Energy Operating Revenue	8,489,990	7,537,865
Operating Expenses ($000)		
Electric Fuel Expense	NA	NA
Cost of Purchased Power	NA	NA
Total Electrical Generation Cost	NA	NA
Gas for Distribution	811,097	568,850
Operations and Maintenance Expense	2,062,722	2,012,916
Other Operating Expenses	2,227,248	1,785,536
Operating DD&A	1,282,378	1,200,729

Fortis Inc. | Income Statement

SNL FINANCIAL	2022 FY	2021 FY
Taxes, Other than Income Tax	0	0
Operating Expense	6,383,445	5,568,031
Operating Margin ($000)		
Income Taxes, Operating	0	0
Recurring Operating Income	2,106,545	1,969,834
Reported Net Operating Income	2,106,545	1,969,834
Other Revenue ($000)		
Partnership Income	NA	5,585
Allowance for Equity Funds - Construction	59,967	61,433
Other Noninterest Income	66,887	71,007
Recurring Revenue	8,616,844	7,675,889
Other Nonrecurring Revenue	0	0
Gain on Sale of Assets	0	0
Nonrecurring Revenue	0	0
Total Revenue	8,616,844	7,675,889
Other Expenses ($000)		
Interest Expense: LT Debt	NA	NA
Other Interest Expense	NA	NA
Interest Paid and Accrued	881,827	831,335
Amortization of Deferred Financing Costs	NA	NA
Interest Capitalized	NA	NA
Allowance for Borrowed Funds - Construction	34,597	31,115
Interest Expense	847,231	800,220
Other Expense	0	0
Asset Writedowns	0	0
Other Nonrecurring Expense	0	0
Nonrecurring Expense	0	0

SNL FINANCIAL	2022 FY	2021 FY
Total Recurring Expense	7,230,676	6,368,251
Total Expenses	7,230,676	6,368,251
Net Income ($000)		
Net Income before Taxes	1,386,168	1,307,638
Current Income Taxes	82,263	69,411
Deferred Income Taxes	139,924	117,280
Deferred Tax Credits	0	0
Other Income Taxes	NA	NA
Provision for Taxes	222,187	186,691
Preferred Divs of Sub	0	0
Other Minority Interest Expense	0	0
Total Minority Interest Expense	0	0
Other After-tax Items	0	0
Trust Preferred Distributions	0	0
Min Int & Oth after-tax Items	0	0
Net Income before Extra	1,163,981	1,120,946
Discontinued Operations	0	0
Change in Accounting Principles	0	0
Early Retirement of Debt	0	0
Other Extraordinary Items	0	0
Extraordinary Items	0	0
Net Income	1,163,981	1,120,946
Net Income Attributable to Noncontrolling Int	92,257	88,559
Net Income Attributable to Parent	1,071,724	1,032,388
Preferred Dividends	49,204	50,263
Other Preferred Dividends after Net Income	0	0
Other Changes to Net Income	0	0
Net Income Avail to Common	1,022,520	982,124
Net Income for Basic EPS	1,022,520	982,124
Net Income for Diluted EPS	1,022,520	982,124

Fortis Inc. | Income Statement

SNL FINANCIAL	2022 FY	2021 FY
Per Share Information ($)		
Basic EPS before Extra	2.14	2.08
Diluted EPS before Extra	2.14	2.08
Basic EPS after Extra	2.14	2.08
Diluted EPS after Extraordinary	2.14	2.08
Avg Basic Shares Out	478,600,000	470,900,000
Avg Diluted Shares (actual)	479,000,000	471,400,000
Common Dividends Declared per Share	1.6914	1.6595

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

S&P Capital IQ PRO

Fortis Inc. | Balance Sheet

TSX:FTS (MI KEY: 4082871; SPCIQ KEY: 875612)

Source: SNL Financial
Period Category: Custom
Period Type: Custom
Reporting Basis: Custom
Sort Order: Custom
Currency: U.S. Dollar (USD)
Magnitude: Thousands (K)

SNL FINANCIAL	2022 FY	2021 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2022	12/31/2021
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.738869	0.790208
Average Exchange Rate	0.768812	0.797827
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD
Current Assets ($000)		
Cash and Cash Equivalents	154,424	103,517
Gross Trade Accounts Receivable	NA	NA
Trade Accounts Receivable Allowance	NA	NA
Net Customer and Trade Accounts Receivable	644,294	448,838
Other Accounts Receivable	0	0
Accounts Receivable	644,294	448,838
Unbilled Revenue	655,377	553,936
Current Inventories	488,392	377,719
Prepaid Expense	107,875	91,664
Current Investments	0	0
Short-term Energy Risk-mgmt Assets	NA	NA
Deferred Taxes, Current	0	0
Other Current Assets	1,103,870	580,012
Current Assets	3,154,232	2,155,687
Property, Plant and Equipment ($000)		

SNL FINANCIAL	2022 FY	2021 FY
Electric PP&E in Service, Gross	29,465,354	28,794,380
Gas PP&E in Service, Gross	6,646,865	6,551,612
Other PP&E in Service, Gross	3,840,641	3,714,767
PP&E in Service, Gross	39,952,860	39,060,759
Total Accumulated Depreciation	10,716,555	10,568,238
Net PP&E in Service	29,236,305	28,492,521
Construction Work in Progress	1,547,192	1,389,975
Net Nuclear Fuel	0	0
Other Net PP&E	129,302	131,965
Net PP&E	30,912,799	30,014,461
Other Assets ($000)		
Securities - Noncurrent	0	0
Nuclear Decommissioning Trust	0	0
Other Investments	84,970	67,958
Investment in Partnerships	NA	72,699
Noncurrent Investments	84,970	140,657
Goodwill	9,209,262	9,261,235
Intangible Assets other than Goodwill	1,143,769	1,061,249
Total Intangible Assets	10,353,032	10,322,484
Long-term Energy Risk-mgmt Assets	NA	NA
Deferred Taxes, Noncurrent	0	0
Regulatory Assets	2,189,269	2,346,917
Total Other Assets	779,507	582,383
Total Assets	47,473,807	45,562,588
Tangible Assets	37,120,776	35,240,105
Current Liabilities ($000)		
Short-term Debt	186,934	195,181
Current Portion of Long-term Debt	1,841,261	1,295,941

SNL FINANCIAL	2022 FY	2021 FY
Short-term and Current Long-term Debt	2,028,195	1,491,122
Current Portion of Preferred Equity	0	0
Accrued Interest Payable	187,673	172,265
Income Taxes Payable	65,020	24,496
Customer Security Deposits	296,286	227,580
Other Accounts Payable and Accrued Expense	1,638,072	1,431,066
Accounts Payable and Accrued Expense	2,187,052	1,855,408
Short-term Energy Risk-mgmt Liabilities	NA	NA
Other Current Liabilities	673,848	448,048
Current Liabilities	4,889,096	3,794,578
Other Liabilities ($000)		
Postretirement Benefits	312,542	584,754
Deferred Income Tax Liability	2,999,808	2,866,083
Deferred Tax Credit	NA	NA
Deferred Tax Liability	NA	NA
Non-current Long-term Debt	19,432,992	19,021,881
Long-term Energy Risk-mgmt Liabilities	NA	NA
Regulatory Liabilities	2,453,045	2,263,945
Total Other Liabilities	364,262	503,362
Total Liabilities	30,596,563	29,034,603
Mezzanine ($000)		
Minority Interest	0	0
Subsidiary Preferred	0	0
Total Minority Interest	0	0
Other Mezzanine Items	0	0
Total Mezzanine Level Items	0	0

Fortis Inc. | Balance Sheet

SNL FINANCIAL	2022 FY	2021 FY
Equity ($000)		
Total Preferred Equity	1,199,184	1,282,507
Common Equity	14,339,230	13,959,020
Equity Attributable to Parent Company	15,538,414	15,241,527
Noncontrolling Interests	1,338,831	1,286,458
Total Equity	16,877,244	16,527,985
Tangible Common Equity	3,986,198	3,636,536
Tangible Equity	6,524,213	6,205,501
Capitalization ($000)		
Equity & Mezzanine Preferred	16,877,244	16,527,985
Total Debt	21,461,187	20,513,003
Total Capitalization, at Book Value	38,338,432	37,040,988
Share Information		
Shares Issued	482,200,000	474,800,000
Treasury Shares	0	0
Common Shares Outstanding (actual)	482,200,000	474,800,000

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S&P Capital IQ PRO

Fortis Inc. | Cash Flow Statement

TSX:FTS (MI KEY: 4082871; SPCIQ KEY: 875612)

Source: SNL Financial
Period Category: Custom: CF
Period Type: Custom: CF
Reporting Basis: Custom: CF
Sort Order: Custom: CF
Currency: U.S. Dollar (USD)
Magnitude: Thousands (K)

SNL FINANCIAL	2022 FY	2021 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2022	12/31/2021
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.738869	0.790208
Average Exchange Rate	0.768812	0.797827
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD
Operating Activity ($000)		
Net Income	1,163,981	1,120,946
Cash Flow: Depreciation and Amortization	1,282,378	1,200,729
Cash Flow: Amortization of Nuclear Fuel	0	0
Cash Flow: Deferred Taxes & Investment Tax Credits	139,924	117,280
Cash Flow: Operating Changes in AFUDC	(59,967)	(61,433)
Cash Flow: Change in Working Capital	(368,261)	(114,887)
Cash Flow: Other Operating Changes in Cash	205,273	56,646
Cash Flow from Operating Activities	2,363,328	2,319,282
Adjusted Cash Flow from Operations ($000)		
Net Income	1,163,981	1,120,946
Cash Flow: Depreciation and Amortization	1,282,378	1,200,729
Cash Flow: Deferred Taxes & Investment Tax Credits	139,924	117,280
Cash Flow: Other Operating Changes in Cash	205,273	56,646
Cash Flow: Amortization of Nuclear Fuel	0	0

Fortis Inc. | Cash Flow Statement

SNL FINANCIAL	2022 FY	2021 FY
Adjusted Cash Flow from Operations	2,791,556	2,495,601
Investing Activity ($000)		
Cash Flow: Capital Expenditures	(2,757,728)	(2,544,269)
Cash Flow from Asset Purchases	(213,730)	(157,172)
Cash Flow from Asset Sales	0	0
Cash Flow from Asset Sales & Purchases	(213,730)	(157,172)
Net Investment in Nuclear Decommissioning Trust	0	0
Cash Flow: Investing Changes in AFUDC	NA	NA
Cash Flow: Other Investing Changes in Cash	(149,150)	(81,378)
Cash Flow from Investing Activities	(3,120,607)	(2,782,819)
Financing Activity ($000)		
Net Proceeds from Issuance of Short-term Debt	NA	NA
Cash Flow: Short-term Debt Repayments	NA	NA
Net Change in Short-term Debt	(16,145)	91,750
Net Proceeds from Issuance of Long-term Debt	7,471,314	5,110,877
Cash Flow: Long-term Debt Repayments	(6,078,996)	(4,294,700)
Net Change in Long-term Debt	1,392,318	816,177
Preferred Equity Net Proceeds	0	0
Cash Flow: Preferred Share Repurchases	0	0
Cash Flow: Net Change in Preferred Issues	0	0
Common Equity Net Proceeds	40,747	47,870
Cash Flow: Common Share Repurchases	0	0
Cash Flow: Net Change in Common Issues	40,747	47,870
Cash Flow: Common Dividends Paid	(517,410)	(485,079)
Preferred Dividends Paid	(49,204)	(50,263)
Dividends Paid	(566,614)	(535,342)
Cash Flow: Other Financing Changes in Cash	(54,586)	(60,635)
Cash Flow from Financing Activities	795,720	359,820

Fortis Inc. | Cash Flow Statement

SNL FINANCIAL	2022 FY	2021 FY
Other Cash Flow ($000)		
Other Cash Flow	21,527	9,574
Net Increase in Cash and Cash Equivalents	59,967	(94,144)
Mark-to-Market Adjustment	NA	NA
Interest Paid	812,634	786,657
Income Taxes Paid	60,736	(10,372)
Dividends Paid to Parent Company	0	0
Projected Capital Expenditures ($000)		
Planned Capital Expenditures for This Fiscal Year	3,197,086	3,134,754
Planned Capital Expenditures for Next Fiscal Year	3,072,956	3,033,608
Planned Capital Expenditures Second Fiscal Year	3,383,281	3,193,230

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CH ENERGY GROUP, INC.
&
CENTRAL HUDSON GAS & ELECTRIC CORP.

ANNUAL FINANCIAL REPORT

for the period ended

DECEMBER 31, 2022

YEAR ENDED DECEMBER 31, 2022

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FINANCIAL STATEMENTS

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INDEPENDENT AUDITOR'S REPORT

To the Shareholder and Board of Directors of CH Energy Group, Inc.

Opinion

We have audited the consolidated financial statements of CH Energy Group Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2022 and 2021, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes to the consolidated financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Other Information Included in the Annual Financial Report

Management is responsible for the other information included in the annual financial report. The other information comprises the information included in the annual financial report but does not include the financial statements and our auditor's report thereon. Our opinion on the financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audits of the financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Deloitte & Touche LLP

Hartford, Connecticut

February 9, 2023

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of Central Hudson Gas & Electric Corporation

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Central Hudson Gas & Electric Corporation (the "Company") as of December 31, 2022 and 2021, the related statements of income, comprehensive income, equity, and cash flows, for each of the three 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 Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company'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 (COSO) and our report dated February 9, 2023 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company'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 Company 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 auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. 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 Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate-Regulation on Various Account Balances and Disclosures —Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company is a regulated electric and natural gas transmission and distribution utility in the state of New York and is subject to regulation by the New York Public Service Commission (“Commission”). The Company defers costs and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those costs and revenues will be recoverable/refundable through the rate-making process in a period different from when they otherwise would have been reflected in income. For the Company, these deferred regulatory assets and liabilities, and the related deferred taxes, are recovered from or reimbursed to customers either by offset as directed by the Commission, through an approved surcharge mechanism or through incorporation in the determination of the revenue requirement used to set new rates. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation.

Rates are generally designed for but do not guarantee the recovery of the Company’s cost of service, including a return on equity. Regulatory decisions can have an impact on the recovery of costs, refunds to customers, the rate of return earned on investment, and the timing and amount of assets to be recovered or liabilities to be refunded through rates. Future recovery of costs and refunds that may be required are dependent upon factors, such as (1) changes in the regulatory environment, (2) the ability to recover costs through regulated rates, (3) recent rate orders to the Company and other regulated entities, and (4) the status of any pending or potential deregulation legislation. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commission will not approve full recovery of such costs or approve recovery on a timely basis in future regulatory decisions. The Commission can reach different conclusions about the recovery of costs, which can have a material impact on the Company’s financial statements.

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 the impact of regulatory orders on various account balances and disclosures. Management judgments include assessing the likelihood of (1) recovery of regulatory assets through future rates, and (2) whether a regulatory liability is due to customers. Given that management’s accounting judgments are based on assumptions about the outcome of future decisions by the Commission, auditing these judgments requires specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the impact of regulatory orders on various account balances and disclosures included the following, among others:

- We tested the effectiveness of internal controls over the initial recognition of amounts as regulated utility plant and as regulatory assets and liabilities, 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, and the related disclosures in the notes to the financial statements.

- We evaluated the Company’s disclosures related to the impacts of rate regulation, including regulatory developments.

- We read and evaluated relevant regulatory orders issued by the Commission for the Company, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and other publicly available information to assess whether this information was properly considered by management in concluding upon the financial statement impacts of rate regulation.

- We obtained and evaluated an analysis from management describing the orders and filings that support management's assertions regarding the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

- For regulatory matters in process, we inspected associated documents and testimony filed with the Commission for any evidence that might contradict management's assertions.

- We read and evaluated the minutes of the Board of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact management's conclusions with respect to the impact of rate regulation on various account balances and disclosures.

Deloitte & Touche LLP

Hartford, Connecticut

February 9, 2023

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of Central Hudson Gas & Electric Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Central Hudson Gas & Electric Corporation (the "Company") 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 Company 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 auditing standards of the Public Company Accounting Oversight Board (United States) (PCAOB) and in accordance with auditing standards generally accepted in the United States of America, the financial statements as of and for the year ended December 31, 2022, of the Company and our report dated February 9, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company'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 Report of Management on Internal Control over Financial Reporting – Central Hudson. Our responsibility is to express an opinion on the Company'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 Company 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 auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. 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.

Deloitte & Touche LLP

Hartford, Connecticut
February 9, 2023

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING – CENTRAL HUDSON

The management of Central Hudson Gas & Electric Corporation ("management") is responsible for establishing and maintaining adequate internal control over financial reporting for Central Hudson Gas & Electric Corporation (the "Corporation") as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. 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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Corporation;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the Corporation are being made only in accordance with authorization of management and directors of the Corporation; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated financial statements.

Internal control over financial reporting includes the controls themselves, monitoring (including internal auditing practices), and actions taken to correct deficiencies as identified.

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.

Management assessed the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2022. Management based this assessment on criteria for effective internal control over financial reporting described in "*Internal Control - Integrated Framework*" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management determined that, as of December 31, 2022, the Corporation maintained effective internal control over financial reporting.

The effectiveness of the Corporation's internal control over financial reporting as of December 31, 2022, has been audited by Deloitte and Touche LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Charles A. Freni, Jr.
President and Chief Executive Officer

Lora Gescheidle
Chief Financial Officer and Treasurer

February 9, 2023

CH ENERGY GROUP
CONSOLIDATED STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2022	2021	2020
Operating Revenues			
Electric	$ 797,612	$ 623,823	$ 552,002
Natural gas	220,744	172,425	159,893
Total Operating Revenues	1,018,356	796,248	711,895
Operating Expenses			
Operation:			
Purchased electricity	323,503	178,737	136,130
Purchased natural gas	79,074	48,260	37,221
Other expenses of operation - regulated activities	361,265	323,707	306,845
Other expenses of operation - non-regulated	136	176	208
Depreciation and amortization	80,016	72,715	66,863
Taxes, other than income tax	78,247	72,837	67,854
Total Operating Expenses	922,241	696,432	615,121
Operating Income	96,115	99,816	96,774
Other Income and Deductions			
Income from unconsolidated affiliates	2,547	1,969	1,151
Interest on regulatory assets and other interest income	3,204	2,925	2,421
Regulatory adjustments for interest costs	(85)	(891)	(211)
Non-service cost components of pension and other post-employment benefits ("OPEB")	39,165	20,903	17,744
Other - net	268	2,648	2,033
Total Other Income	45,099	27,554	23,138
Interest Charges			
Interest on long-term debt	40,137	34,231	32,778
Interest on regulatory liabilities and other interest	764	2,370	2,769
Total Interest Charges	40,901	36,601	35,547
Income Before Income Taxes	100,313	90,769	84,365
Income Tax Expense	21,180	16,816	15,262
Net Income	$ 79,133	$ 73,953	$ 69,103

CH ENERGY GROUP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	2022	Year Ended December 31, 2021	2020
Net Income	$ 79,133	$ 73,953	$ 69,103
Other Comprehensive Income:			
Employee future benefits, net of tax expense	147	180	238
Comprehensive Income	$ 79,280	$ 74,133	$ 69,341

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2022	2021	2020
Operating Activities:			
Net income	$ 79,133	$ 73,953	$ 69,103
Adjustments to reconcile net income to net cash (used in) provided from operating activities:			
Depreciation	62,580	58,910	54,558
Amortization	17,436	13,805	12,305
Deferred income taxes - net	21,118	16,653	15,182
Uncollectible expense	8,170	6,074	10,010
Distributed (undistributed) equity in earnings of unconsolidated affiliates	41	(1,844)	(340)
Pension (credit) expense	(7,507)	(400)	2,340
OPEB credit	(7,057)	(6,048)	(6,355)
Regulatory liability - rate moderation	(4,371)	(8,543)	(13,748)
Regulatory asset - revenue decoupling mechanism ("RDM") recorded	2,868	12,806	22,617
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	(114,231)	(53,956)	(14,603)
Fuel, materials, and supplies	(7,122)	(439)	2,534
Special deposits and prepayments	(6,498)	(3,997)	(5,401)
Income and other taxes	229	(198)	311
Accounts payable	20,729	3,703	9,554
Accrued interest	2,500	571	581
Customer advances	(1,152)	2,812	389
Other advances	(10,622)	3,738	235
Coronavirus Aid, Relief, and Economic Security ("CARES") Act	(2,603)	(2,603)	5,206
Pension plan contribution	(1,468)	(1,475)	(1,130)
OPEB contribution	(528)	(812)	(1,081)
Regulatory asset - RDM refunded	(6,341)	(34,069)	(12,450)
Regulatory asset - major storm	(37,067)	(7,404)	(19,640)
Regulatory asset - site investigation and remediation ("SIR")	6,815	5,083	(2,514)
Regulatory asset - arrears management program ("AMP")	(3,039)	-	-
Regulatory asset - uncollectible write-offs	(4,144)	-	-
Regulatory liability - energy efficiency programs including clean energy fund ("CEF")	(16,375)	(21,103)	(17,776)
Regulatory asset - rate adjustment mechanisms ("RAM")	13,121	10,651	9,452
Regulatory asset - deferred natural gas and electric costs	(35,037)	(17,454)	4,172
Other - net	(3,870)	12,491	7,518
Net cash (used in) provided from operating activities	(34,292)	60,905	131,029
Investing Activities:			
Additions to utility plant	(224,842)	(231,582)	(252,857)
Proceeds from sale of assets	4,574	-	-
Other - net	(4,331)	(8,687)	(3,975)
Net cash used in investing activities	(224,599)	(240,269)	(256,832)
Financing Activities:			
Repayment of long-term debt	(25,364)	(45,987)	(41,718)
Proceeds from issuance of long-term debt	220,000	130,000	130,000
Net change in short-term borrowings	(2,000)	92,000	15,000
Capital contribution	54,300	9,396	15,000
Other - net	(1,164)	(723)	(747)
Net cash provided from financing activities	245,772	184,686	117,535
Net Change in Cash, Cash Equivalents, and Restricted Cash	(13,119)	5,322	(8,268)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	18,129	12,807	21,075
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 5,010	$ 18,129	$ 12,807
Supplemental Disclosure of Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 37,132	$ 32,528	$ 30,967
Federal and state income taxes paid, net	$ 2,671	$ 2,387	$ 52
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:			
Operating cash flows used in operating leases	$ (409)	$ (542)	$ (668)
Non-Cash Operating Activities:			
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 85	$ 387	$ -
Non-Cash Investing Activities:			
Accrued capital expenditures	$ 16,472	$ 21,683	$ 21,241

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP
CONSOLIDATED BALANCE SHEET
(In Thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Utility Plant (Note 3)		
Electric	$ 1,768,092	$ 1,687,291
Natural gas	788,978	734,165
Common	448,796	425,970
Gross Utility Plant	3,005,866	2,847,426
Less: Accumulated depreciation	698,940	649,513
Net	2,306,926	2,197,913
Construction work in progress	146,661	118,182
Net Utility Plant	2,453,587	2,316,095
Non-utility property & plant	524	524
Net Non-Utility Property & Plant	524	524
Current Assets		
Cash and cash equivalents (Note 1)	3,237	7,339
Accounts receivable from customers - net of allowance for uncollectible accounts of $11.0 million and $9.7 million, respectively (Note 2)	216,680	120,600
Accounts receivable - affiliates (Note 18)	441	1,390
Accrued unbilled utility revenues - net of allowance for uncollectible accounts of $0.2 million and $1.5 million, respectively (Note 2)	27,823	25,378
Other receivables	25,906	17,421
Fuel, materials, and supplies (Note 1)	31,238	24,116
Regulatory assets (Note 4)	125,980	78,849
Income tax receivable	502	671
Fair value of derivative instruments (Note 16)	315	1,768
Special deposits and prepayments	42,706	36,208
Total Current Assets	474,828	313,740
Deferred Charges and Other Assets		
Regulatory assets - other (Note 4)	226,069	174,483
Prefunded pension costs (Note 12)	59,365	70,222
Prefunded OPEB costs (Note 12)	31,462	30,480
Investments in unconsolidated affiliates (Note 6)	23,523	15,252
Other investments (Note 17)	54,179	56,875
Other	10,497	18,988
Total Deferred Charges and Other Assets	405,095	366,300
Total Assets	$ 3,334,034	$ 2,996,659

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP
CONSOLIDATED BALANCE SHEET (CONT'D)
(In Thousands, except share amounts)

CAPITALIZATION AND LIABILITIES	December 31, 2022	December 31, 2021
Capitalization (Note 10)		
CH Energy Group Common Shareholders' Equity		
Common Stock (30,000,000 shares authorized: $0.01 par value; 15,961,400 shares issued and outstanding)	$ 160	$ 160
Paid-in capital	488,102	433,802
Retained earnings	584,434	505,301
Accumulated other comprehensive income	166	19
Total Equity	1,072,862	939,282
Long-term debt (Note 11)		
Principal amount	1,124,046	906,146
Unamortized debt issuance costs	(5,838)	(5,139)
Net long-term debt	1,118,208	901,007
Total Capitalization	2,191,070	1,840,289
Current Liabilities		
Current maturities of long-term debt (Note 11)	2,100	25,364
Short-term borrowings (Note 9)	105,000	107,000
Accounts payable	81,110	64,722
Accounts payable - affiliates (Note 18)	624	-
Accrued interest	10,685	8,185
Accrued vacation and payroll	10,861	11,590
Customer advances	16,953	18,105
Customer deposits	6,846	7,539
Regulatory liabilities (Note 4)	75,053	63,456
Fair value of derivative instruments (Note 16)	14,034	7,563
Accrued environmental remediation costs (Note 14)	3,717	5,900
Other current liabilities	31,926	37,294
Total Current Liabilities	358,909	356,718
Deferred Credits and Other Liabilities		
Regulatory liabilities - deferred pension costs (Note 4)	74,898	90,934
Regulatory liabilities - deferred OPEB costs (Note 4)	24,652	31,032
Regulatory liabilities - other (Note 4)	262,735	272,555
Operating reserves	2,892	5,006
Accrued environmental remediation costs (Note 14)	70,156	65,753
Other liabilities	32,361	48,373
Total Deferred Credits and Other Liabilities	467,694	513,653
Accumulated Deferred Income Tax (Note 5)	316,361	285,999
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 3,334,034	$ 2,996,659

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP
CONSOLIDATED STATEMENT OF EQUITY
(In Thousands, except share amounts)

	CH Energy Group Common Shareholders										
	Common Stock Shares Issued		Common Stock Amount		Paid-In Capital		Retained Earnings		AOCI*		Total Equity
Balance at December 31, 2019	15,961,400	$	160	$	409,406	$	363,445	$	(399)	$	772,612
Accounting Standard Adoption – cumulative effect adjustment (Note 1)							(1,200)				(1,200)
Net income							69,103				69,103
Capital contributions					15,000						15,000
Employee future benefits, net of tax									238		238
Balance at December 31, 2020	15,961,400	$	160	$	424,406	$	431,348	$	(161)	$	855,753
Contribution from Parent - tax sharing agreement					4,996						4,996
Net income							73,953				73,953
Capital contributions					4,400						4,400
Employee future benefits, net of tax									180		180
Balance at December 31, 2021	15,961,400	$	160	$	433,802	$	505,301	$	19	$	939,282
Net income							79,133				79,133
Capital contributions					54,300						54,300
Employee future benefits, net of tax									147		147
Balance at December 31, 2022	15,961,400	$	160	$	488,102	$	584,434	$	166	$	1,072,862

*Accumulated other comprehensive income (loss)

CENTRAL HUDSON
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2022	2021	2020
Operating Revenues			
Electric	$ 797,612	$ 623,823	$ 552,002
Natural gas	220,744	172,425	159,893
Total Operating Revenues	1,018,356	796,248	711,895
Operating Expenses			
Operation:			
Purchased electricity	323,503	178,737	136,130
Purchased natural gas	79,074	48,260	37,221
Other expenses of operation	361,265	323,707	306,845
Depreciation and amortization	80,016	72,715	66,863
Taxes, other than income tax	78,068	72,795	67,821
Total Operating Expenses	921,926	696,214	614,880
Operating Income	96,430	100,034	97,015
Other Income and Deductions			
Interest on regulatory assets and other interest income	3,204	2,924	2,415
Regulatory adjustments for interest costs	(85)	(891)	(211)
Non-service cost components of pension and OPEB	39,192	20,932	17,768
Other - net	229	2,652	2,046
Total Other Income	42,540	25,617	22,018
Interest Charges			
Interest on long-term debt	39,583	33,550	31,978
Interest on regulatory liabilities and other interest	764	2,370	2,769
Total Interest Charges	40,347	35,920	34,747
Income Before Income Taxes	98,623	89,731	84,286
Income Tax Expense	20,531	16,108	15,145
Net Income	$ 78,092	$ 73,623	$ 69,141

CENTRAL HUDSON
STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31, 2022	2021	2020
Net Income	$ 78,092	$ 73,623	$ 69,141
Other Comprehensive Income:			
Employee future benefits, net of tax expense	147	180	238
Comprehensive Income	$ 78,239	$ 73,803	$ 69,379

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
STATEMENT OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 2022	2021	2020
Operating Activities:			
Net income	$ 78,092	$ 73,623	$ 69,141
Adjustments to reconcile net income to net cash (used in) provided from operating activities:			
Depreciation	62,580	58,910	54,558
Amortization	17,436	13,805	12,305
Deferred income taxes - net	20,541	16,107	15,163
Uncollectible expense	8,170	6,074	10,010
Pension credit	(7,507)	(400)	2,340
OPEB credit	(7,057)	(6,048)	(6,355)
Regulatory liability - rate moderation	(4,371)	(8,543)	(13,748)
Regulatory asset - RDM recorded	2,868	12,806	22,617
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	(115,321)	(53,769)	(14,288)
Fuel, materials, and supplies	(7,122)	(439)	2,534
Special deposits and prepayments	(6,489)	(3,997)	(5,424)
Income and other taxes	(2)	(31)	(273)
Accounts payable	20,673	4,487	9,019
Accrued interest	2,506	575	587
Customer advances	(1,152)	2,812	389
Other advances	(10,622)	3,738	235
CARES Act	(2,603)	(2,603)	5,206
Pension plan contribution	(1,468)	(1,475)	(1,130)
OPEB contribution	(528)	(812)	(1,081)
Regulatory asset - RDM refunded	(6,341)	(34,069)	(12,450)
Regulatory asset - major storm	(37,067)	(7,404)	(19,640)
Regulatory asset - SIR	6,815	5,083	(2,514)
Regulatory asset - arrears management program	(3,039)	-	-
Regulatory asset - uncollectible write-offs	(4,144)	-	-
Regulatory liability - energy efficiency programs including CEF	(16,375)	(21,103)	(17,776)
Regulatory asset - RAM	13,121	10,651	9,452
Regulatory asset - deferred natural gas and electric costs	(35,037)	(17,454)	4,172
Other - net	(773)	11,904	7,646
Net cash (used in) provided from operating activities	(34,216)	62,428	130,695
Investing Activities:			
Additions to utility plant	(224,842)	(231,582)	(252,857)
Proceeds from sale of assets	4,574	-	-
Other - net	3,878	(4,626)	(3,983)
Net cash used in investing activities	(216,390)	(236,208)	(256,840)
Financing Activities:			
Repayment of long-term debt	(23,400)	(44,150)	(40,000)
Proceeds from issuance of long-term debt	220,000	130,000	130,000
Net change in short-term borrowings	(2,000)	92,000	15,000
Capital contribution	46,000	6,000	12,000
Other - net	(1,164)	(723)	(747)
Net cash provided from financing activities	239,436	183,127	116,253
Net Change in Cash, Cash Equivalents, and Restricted Cash	(11,170)	9,347	(9,892)
Cash, Cash Equivalents, and Restricted Cash - Beginning of Period	14,541	5,194	15,086
Cash, Cash Equivalents, and Restricted Cash - End of Period	$ 3,371	$ 14,541	$ 5,194
Supplemental Disclosure of Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 36,573	$ 31,842	$ 30,162
Federal and state income taxes paid, net	$ 2,172	$ 2,021	$ 501
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:			
Operating cash flows used in operating leases	$ (409)	$ (542)	$ (668)
Non-Cash Operating Activities:			
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 85	$ 387	$ -
Non-Cash Investing Activities:			
Accrued capital expenditures	$ 16,472	$ 21,683	$ 21,241

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
BALANCE SHEET
(In Thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Utility Plant (Note 3)		
Electric	$ 1,768,092	$ 1,687,291
Natural gas	788,978	734,165
Common	448,796	425,970
Gross Utility Plant	3,005,866	2,847,426
Less: Accumulated depreciation	698,940	649,513
Net	2,306,926	2,197,913
Construction work in progress	146,661	118,182
Net Utility Plant	2,453,587	2,316,095
Non-Utility Property and Plant	524	524
Net Non-Utility Property and Plant	524	524
Current Assets		
Cash and cash equivalents (Note 1)	1,598	3,751
Accounts receivable from customers - net of allowance for uncollectible accounts of $11.0 million and $9.7 million, respectively (Note 2)	216,680	120,600
Accrued unbilled utility revenues - net of allowance for uncollectible accounts of $0.2 million and $1.5 million, respectively (Note 2)	27,823	25,378
Other receivables	26,121	17,493
Fuel, materials, and supplies (Note 1)	31,238	24,116
Regulatory assets (Note 4)	125,980	78,849
Fair value of derivative instruments (Note 16)	315	1,768
Special deposits and prepayments	42,697	36,208
Total Current Assets	472,452	308,163
Deferred Charges and Other Assets		
Regulatory assets - other (Note 4)	226,069	174,483
Prefunded pension costs (Note 12)	59,559	70,454
Prefunded OPEB costs (Note 12)	31,462	30,480
Other investments	53,294	55,896
Other	10,495	18,988
Total Deferred Charges and Other Assets	380,879	350,301
Total Assets	$ 3,307,442	$ 2,975,083

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
BALANCE SHEET (CONT'D)
(In Thousands, except share amounts)

	December 31, 2022	December 31, 2021
CAPITALIZATION AND LIABILITIES		
Capitalization (Note 10)		
Common Stock (30,000,000 shares authorized: $5 par value; 16,862,087 shares issued and outstanding)	$ 84,311	$ 84,311
Paid-in capital	326,452	280,452
Accumulated other comprehensive income	166	19
Retained earnings	650,113	572,021
Capital stock expense	(4,633)	(4,633)
Total Equity	1,056,409	932,170
Long-term debt (Note 11)		
Principal amount	1,119,400	899,400
Unamortized debt issuance costs	(5,810)	(5,102)
Net long-term debt	1,113,590	894,298
Total Capitalization	2,169,999	1,826,468
Current Liabilities		
Current maturities of long-term debt (Note 11)	-	23,400
Short-term borrowings (Note 9)	105,000	107,000
Accounts payable	82,288	65,332
Accrued interest	10,666	8,160
Accrued vacation and payroll	10,861	11,590
Customer advances	16,953	18,105
Customer deposits	6,846	7,539
Regulatory liabilities (Note 4)	75,053	63,456
Fair value of derivative instruments (Note 16)	14,034	7,563
Accrued environmental remediation costs (Note 14)	3,717	5,900
Other current liabilities	30,792	34,924
Total Current Liabilities	356,210	352,969
Deferred Credits and Other Liabilities		
Regulatory liabilities - deferred pension costs (Note 4)	74,898	90,934
Regulatory liabilities - deferred OPEB costs (Note 4)	24,652	31,032
Regulatory liabilities - other (Note 4)	262,735	272,555
Operating reserves	2,892	5,006
Accrued environmental remediation costs (Note 14)	70,156	65,753
Other liabilities	31,299	45,491
Total Deferred Credits and Other Liabilities	466,632	510,771
Accumulated Deferred Income Tax (Note 5)	314,601	284,875
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 3,307,442	$ 2,975,083

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON

STATEMENT OF EQUITY

(In Thousands, except share amounts)

	Central Hudson Common Shareholders						
	Common Stock Shares Issued	Common Stock Amount	Paid-In Capital	Capital Stock Expense	Retained Earnings	AOCI*	Total Equity
Balance at December 31, 2019	16,862,087	$ 84,311	$ 262,452	$ (4,633)	$ 430,457	$ (399)	$ 772,188
Accounting Standard Adoption – cumulative effect adjustment (Note 1)					(1,200)		(1,200)
Net income					69,141		69,141
Capital contributions			12,000				12,000
Employee future benefits, net of tax						238	238
Balance at December 31, 2020	16,862,087	$ 84,311	$ 274,452	$ (4,633)	$ 498,398	$ (161)	$ 852,367
Net income					73,623		73,623
Capital contributions			6,000				6,000
Employee future benefits, net of tax						180	180
Balance at December 31, 2021	16,862,087	$ 84,311	$ 280,452	$ (4,633)	$ 572,021	$ 19	$ 932,170
Net income					78,092		78,092
Capital contributions			46,000				46,000
Employee future benefits, net of tax						147	147
Balance at December 31, 2022	16,862,087	$ 84,311	$ 326,452	$ (4,633)	$ 650,113	$ 166	$ 1,056,409

*Accumulated other comprehensive income (loss)

The Notes to Financial Statements are an integral part hereof.

NOTE 1 – Summary of Significant Accounting Policies

Corporate Structure

CH Energy Group is the holding company parent corporation of four principal, wholly owned subsidiaries, Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"), Central Hudson Electric Transmission LLC ("CHET"), Central Hudson Enterprises Corporation ("CHEC"), and Central Hudson Gas Transmission LLC ("CHGT"). CH Energy Group's common stock is indirectly owned by Fortis Inc. ("Fortis"), which is a leader in the North American regulated electric and gas utility industry. Central Hudson is a regulated electric and natural gas transmission and distribution utility. CH Energy Group formed CHET to hold its 6.1% ownership interest in New York Transco LLC ("Transco"). CHGT was formed to hold CH Energy Group's ownership stake in possible gas transmission pipeline opportunities in New York State. As of December 31, 2022, there has been no activity in CHGT. CHEC has ownership interests in certain non-regulated subsidiaries that are less than 100% owned.

Basis of Presentation

This Annual Financial Report is a combined report of CH Energy Group and Central Hudson. The Notes to the Consolidated Financial Statements apply to both CH Energy Group and Central Hudson. CH Energy Group's Consolidated Financial Statements include the accounts of CH Energy Group and its wholly owned subsidiaries, which include Central Hudson, CHET, CHGT and CHEC. All intercompany balances and transactions have been eliminated in consolidation. CHEC's investments in limited partnerships and limited liability companies and CHET's investment in Transco are accounted for under the equity method.

The Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), which for regulated utilities, includes specific accounting guidance for regulated operations.

Preparation of the financial statements in accordance with GAAP includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, and the disclosures of the contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Current estimates as of and for the year ended December 31, 2022, reflect management's best assumptions at this time. As with all estimates, actual results may differ from those estimated. Estimates may be subject to future uncertainties, including the continued impacts on Central Hudson's service territory and customers resulting from legislative mandates and policies, which could affect the allowance for uncollectible accounts.

Estimates are also reflected for certain commitments and contingencies, where there is sufficient basis to project a future obligation. Disclosures related to these certain commitments and contingencies are included in Note 14 - "Commitments and Contingencies".

Regulatory Accounting Policies

Central Hudson is subject to cost-based rate regulation. As a result, the effects of regulatory actions are required to be reflected in the financial statements. Regulatory accounting guidance results in differences in the application of GAAP between regulated and non-regulated businesses and requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as expense or revenue in non-regulated businesses. Regulated utilities, such as Central Hudson, defer costs and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those costs and revenues will be recoverable/refundable through the rate-making process in a period different from when they otherwise would have been reflected in income. For Central Hudson, these deferred regulatory assets and liabilities and the related deferred taxes, are recovered from or reimbursed to customers either by offset as directed by the PSC, through an approved surcharge mechanism or through incorporation in the determination of revenue requirement used to set new rates. Changes in regulatory assets and liabilities are reflected in the Consolidated Statement of Income either in the period in which the amounts are recovered through a surcharge, are reflected in rates or when the criteria for recording the revenues are met. Current accounting practices reflect the regulatory accounting authorized in Central Hudson's most recent Rate Orders. On June 14, 2018, the PSC issued an Order Approving Rate Plan in Cases 17-E-0459 and 17-G-0460 (the "2018 Rate Order") and on November 18, 2021, the PSC issued an Order Approving Rate Plan in Cases 20-E-0428 and 20-G-0429 (the "2021 Rate Order"). On October 4, 2021, the Federal Energy Regulatory Commission ("FERC") approved Facilities Charge for System Deliverability Upgrades ("SDU") under Rate Schedule 12 of the New York Independent System Operator ("NYISO") to be collected via the Open Access Transmission Tariff ("OATT"). See Note 4 – "Regulatory Matters" for additional information regarding regulatory accounting.

Management periodically assesses whether the regulatory assets are probable of future recovery by considering factors, such as changes in the applicable regulatory and political environments, the ability to recover costs through regulated rates, recent rate orders to Central Hudson and other regulated entities and the status of any pending or potential deregulation legislation. Based on this assessment, management believes the existing regulatory assets are probable for recovery. This assessment reflects the current political and regulatory climate at the state and federal levels and is subject to change in the future. If future recovery of costs ceases to be probable, the regulatory asset would be written off, which could materially impact earnings. Regulatory agencies can provide flexibility in the manner and timing of recovery of regulatory assets.

Rates, Revenues, and Adjustment Mechanisms

Central Hudson's electric and natural gas retail rates are regulated by the PSC. Wholesale transmission rates, facilities charges, and rates for electricity sold for resale in interstate commerce are regulated by the FERC and are collected via the OATT administered by the NYISO or directly by the Company.

Central Hudson's tariffs for retail electric and natural gas service include purchased electricity and purchased natural gas cost adjustment mechanisms, by which electric and natural gas rates are set to recover the actual purchased electricity and purchased natural gas costs, including hedging costs, incurred in providing these services. In addition, the tariffs include adjustment mechanisms to recover from or refund to customers certain revenues and costs that have been deferred such as RDMs, Rate Moderators, incentives earned, or other Earnings Adjustment Mechanisms ("EAMs") and other specified accumulated deferred balances recovered via the RAM as defined in the Rate Orders. See Note 4 – "Regulatory Matters" for definitions. RDMs generally provide the ability to record revenue equal to revenue targets authorized by the PSC and used for the development of rates for most of Central Hudson's customers.

Revenue Recognition

Revenue from Contracts with Customers

Central Hudson records revenue as electric and natural gas is delivered based on either the customers' meter read or estimated usage for the month. For full-service customers, this includes delivery and supply of electricity and natural gas. For retail choice customers, this includes delivery only as these customers purchase supply from a retail marketer. Customers simultaneously receive and consume the benefits provided by Central Hudson. Revenue consists of a fixed customer charge and a charge per kilowatt hour ("kWh") or 100 cubic feet ("Ccf"), that is fixed at the time of delivery. Additionally, certain non-residential electric service customers pay a per KW demand charge which is also fixed at the time of delivery. All performance obligations are satisfied for tariff sales at the time of delivery. Amounts billed to customers are due within 20 days from the date the bill was rendered, and any payment not received by the due date is considered delinquent and incurs a late payment fee. Effective April 1, 2020, Central Hudson temporarily suspended finance charges on past due balances to help mitigate the impacts of the Coronavirus pandemic (“COVID-19”) on our customers. The 2021 Rate Order provided authorization to defer for future recovery from customers any over or under collection of finance charges, including retroactive recovery of the amounts from 2020. As such, this suspension of finance charges did not have an impact on earnings.

Central Hudson records an estimate of unbilled revenue for service rendered to customers after their billing date and through the end of the month. Unbilled revenues are dependent on several factors that require management’s judgment, including estimates of retail sales and customer usage patterns.

Central Hudson receives payments from certain customers based on a predetermined budget billing schedule. Budget billing does not represent a contract asset or liability, but rather just a receivable/liability because there are no further performance obligations required to be satisfied before the Company has the right to collect/refund the customer’s consideration. Consideration is due when control of the energy is transferred to the customer and is satisfied with the passage of time. Budget billing liability balances are recorded within the customer advances line item in the balance sheet.

Central Hudson provides discounts through certain customer assistance programs intended to help low to moderate income families manage their energy burden as prescribed in the 2021 Rate Order with a full deferral mechanism. Discounts available under these programs are determined at the time the performance obligation is satisfied and are recorded as an expense to match revenue collected in rates for the benefit of eligible customers.

Alternative Revenues

In accordance with Accounting Standard Codification (“ASC”) 980 and as authorized by the PSC, Central Hudson records alternative revenues in response to past activities or completed events, if certain criteria are met. Central Hudson has identified alternative revenue programs in both its electric and natural gas revenues. Alternative revenues are generally intended to compensate a regulated utility for fluctuations in revenue due to weather abnormalities, external factors, and demand side initiatives promoted by the regulator, as well as incentive awards if the utility achieves certain objectives, such as reaching specified milestones associated with energy efficiency programs. Central Hudson recognizes alternative revenues when the criteria defined in ASC 980 have been met and not when billed to customers.

Other Revenues

Other revenues, which are not contract revenues, consist of pole attachment rents, finance charges, miscellaneous fees, and other revenue adjustments. Included in other revenue adjustments is the reversal of previously recognized deferrals as they are billed (collected/refunded to customers) pursuant to PSC Orders.

Cash and Cash Equivalents

CH Energy Group and Central Hudson consider temporary cash investments with a maturity (when purchased) of three months or less to be cash equivalents.

Restricted Cash

Restricted cash primarily consists of cash collected from developers and held in escrow related to a SDU project pursuant to terms and conditions of the NYISO OATT.

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported on the Balance Sheets for CH Energy Group and Central Hudson that sum to the total of the same such amounts shown in the corresponding Statements of Cash Flows.

CH Energy Group

(In Thousands)

	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 3,237	$ 7,339
Restricted cash included in other long-term assets	1,773	10,790
Total Cash, Cash Equivalents, and Restricted Cash as shown in the Statement of Cash Flows	$ 5,010	$ 18,129

Central Hudson

(In Thousands)

	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 1,598	$ 3,751
Restricted cash included in other long-term assets	1,773	10,790
Total Cash, Cash Equivalents, and Restricted Cash as shown in the Statement of Cash Flows	$ 3,371	$ 14,541

Accounts Receivable and Allowance for Uncollectible Accounts

Receivables and unbilled utility revenues are carried at net realizable value, based on the allowance for credit losses model. The accounts receivable balance also reflects Central Hudson's purchase of receivables from energy service companies to support the retail choice programs. The allowance for uncollectible accounts reflects management's best estimate of expected credit losses to reduce accounts receivable for amounts estimated to be uncollectible. Estimates for uncollectible accounts are based on accounts receivable aging data, as well as consideration of various quantitative and qualitative factors, including special collection issues and current and forecasted economic conditions. Finance charges can be charged on accounts receivable balances that have been outstanding for more than 20 days. See Note 2 – "Revenues and Receivables" for a discussion of the impact of legislative mandates instituted during the COVID-19 pandemic on finance charges and other revenue.

Financial Instruments

CH Energy Group and Central Hudson use reasonable and supportable forecasts in the estimate of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. On December 31, 2022 and December 31, 2021, there were no expected credit losses on financial instruments other than those on accounts receivable and unbilled utility revenues.

Fuel, Materials, and Supplies

The following is a summary of CH Energy Group's and Central Hudson's inventory of Fuel, Materials, and Supplies valued using the average cost method (In Thousands):

	December 31, 2022	December 31, 2021
Fuel used in electric generation	434	491
Materials and supplies	30,804	23,625
Total	$ 31,238	$ 24,116

Effective August 1, 2020, Central Hudson entered into an Asset Management Agreement (“AMA”) with a third party related to its natural gas transport and storage capacity. Central Hudson continues to make purchases of natural gas in advance of the peak winter season to hedge against price volatility for its customers. However, based on the terms of the agreement, the third party will maintain control and title over the physical natural gas in storage until the end of the contract term. Amounts related to the AMA are recorded in “Special deposits and prepayments” in CH Energy Group’s and Central Hudson’s Balance Sheets.

Utility Plant - Central Hudson

The regulated assets of Central Hudson include electric, natural gas, and common assets, which are listed under the heading “Utility Plant” on CH Energy Group’s Consolidated Balance Sheet and Central Hudson’s Balance Sheet. The accumulated depreciation associated with these regulated assets is also reported on the Balance Sheets.

The cost of additions to the utility plant and replacements of retired units of property are capitalized at original cost. Capitalized costs include labor, materials and supplies, indirect charges for items such as transportation, certain administrative costs, certain taxes, service cost components of pension and other employee benefits, and allowances for funds used during construction (“AFUDC”), less contributions in aid of construction.

AFUDC is defined as the net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used. The concurrent credit for the amount so capitalized is reported in the Consolidated Statement of Income as follows: the portion applicable to borrowed funds is reported as a reduction of interest charges, while the portion applicable to other funds (the equity component) is reported as other income. AFUDC rates are determined in accordance with FERC and PSC regulations. The AFUDC rates were 3.7% in 2022, 6.2% in 2021, and 5.95% in 2020.

The replacement of minor items of property is included in operating expenses. The original cost of property, together with removal cost less salvage, is charged to accumulated depreciation at the time the property is retired and removed from service as required by the PSC.

For additional information see Note 3 – “Utility Plant – Central Hudson.”

Depreciation and Amortization

Central Hudson’s depreciation and amortization provisions are computed on the straight-line method using PSC-approved rates. The anticipated costs of removing assets upon retirement are generally provided for over the life of those assets as a component of depreciation expense and, for regulatory reporting purposes, are reflected in accumulated depreciation until the costs are incurred, which is consistent with industry practice. Current accounting guidance related to asset retirement precludes the recognition of expected future retirement obligations as a component of depreciation expense or accumulated depreciation. Central Hudson, however, is required to use depreciation methods and rates approved by the PSC under regulatory accounting. Central Hudson reclassifies the cost of removal recovered more than amounts incurred to date from accumulated depreciation to regulatory liabilities for presentation in its Balance Sheet in accordance with GAAP.

Central Hudson performs depreciation studies periodically and, upon approval by the PSC, adjusts the depreciation rates of its various classes of depreciable property. Central Hudson’s composite rates for depreciation, inclusive of intangible amortization, were 2.99% in 2022, 2.92% in 2021, and in 2020 was 2.90% of the original average cost of depreciable property. The ratio of the amount of accumulated depreciation to the original cost of the depreciable property at December 31, 2022, 2021, and 2020 was 23.5%, 23.0%, and 23.3%, respectively.

Asset Retirement Obligations

Central Hudson records Asset Retirement Obligations ("AROs") for the incremental removal costs, resulting from legal and environmental obligations associated with the retirement of certain utility plant assets, as a liability at fair value with a corresponding increase to utility capital assets, in the period in which the costs are known and estimable. The fair value of AROs is based on an estimate of the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to accrete the liability for the passage of time and record any changes in the estimated future cash flows of the incremental obligation. Accretion and depreciation expenses associated with AROs are recorded as regulatory assets. Actual costs incurred reduce the liability. The regulatory assets for accretion and depreciation are recovered through the accumulated depreciation reserve upon the retirement of the asset.

Impairment of Long-Lived Assets

Central Hudson reviews long-lived assets for impairment at least annually. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer electricity and natural gas delivery rates approved by the PSC. The net cash flows for regulated entities are not asset-specific but are pooled for the entire regulated utility.

Leases

Beginning on January 1, 2019, when a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a right-of-use asset and lease liability are recognized. Central Hudson measures the right-of-use asset and lease liability at the present value of future lease payments, excluding variable payments based on usage or performance. Central Hudson calculates the present value using a lease-specific secured borrowing rate based on the remaining lease term. Central Hudson has elected the practical expedient to combine lease components (e.g. rent, real estate taxes, and insurance costs) and non-lease components (e.g. common area maintenance costs) and account for them as a single lease component. Central Hudson includes options to extend a lease in the lease term when it is reasonably certain that the option will be exercised. Leases with a term, including renewal options, of twelve months or less are not recorded on the balance sheet.

Research and Development

Central Hudson is engaged in the conduct and support of research and development ("R&D") activities that are focused on the improvement of existing energy technologies and the development of new technologies for the delivery and customer use of energy. R&D expenditures are provided for in Central Hudson's rates charged to customers for electric and natural gas delivery service, with any differences between actual R&D expense and the rate allowances deferred for future recovery from or return to customers. See Note 7 – "Research and Development" for additional details.

Debt Issuance Costs

Expenses incurred in connection with CH Energy Group's or Central Hudson's debt issuance and any discount or premium on debt are deferred and amortized over the lives of the related issues. When long-term debt is reacquired or redeemed, regulatory accounting permits the deferral of related unamortized debt expense and reacquisition costs to be amortized over the remaining original life of the debt retired. The amortization of debt costs for reacquired debt is incorporated in the revenue requirement for delivery rates as authorized by the PSC. See Note 11 – "Capitalization – Long-Term Debt" for additional details.

Income Tax

CH Energy Group and its subsidiaries file consolidated federal income tax returns with FortisUS Inc. ("FortisUS") and, depending on the state, either standalone or consolidated state income tax returns. Income taxes are deferred for all temporary differences between the financial statement and the tax basis of assets and liabilities, under the asset and liability method in accordance with current accounting guidance for income taxes. Certain deferred income taxes are recorded with offsetting regulatory assets or liabilities by Central Hudson to recognize that income taxes will be recovered or refunded through future rates. For federal and state income tax purposes, CH Energy Group and its subsidiaries use an accelerated method of depreciation and generally use the shortest life permitted for each class of assets. Central Hudson follows the normalization method of accounting, which spreads the tax benefits associated with utility assets over the same time period that the costs of those assets are recovered from customers. Normalization is required as a prerequisite for utilities claiming accelerated depreciation and certain tax credits. Deferred investment tax credits are amortized over the estimated life of the properties giving rise to the credits. For state income tax purposes, Central Hudson uses book depreciation for property placed in service in 1999 or earlier in accordance with transition property rules under Article 9-A of the New York State Tax Law. See Note 5 – "Income Tax" for additional information regarding income taxes and the Tax Cuts and Jobs Act.

Post-Employment and Other Benefits

Central Hudson sponsors a noncontributory Retirement Income Plan ("Retirement Plan") for all management, professional, and supervisory employees hired before January 1, 2008 and for all Union employees hired before May 1, 2008. Benefits are based on years of service and compensation. Additionally, Central Hudson maintains a Supplemental Executive Retirement Plan ("SERP") for certain members of management. Central Hudson also provides OPEB plans, which include certain health care and life insurance benefits for retirees hired within the same time periods as stated above.

Central Hudson recognizes the funded status of the Retirement Plan and SERP (collectively "Pension") and OPEB defined benefit plans on its balance sheet. The funded status is measured as the difference between the fair value of qualified plans' assets and the projected benefit obligation ("PBO") for the plans. The Pension funded status includes the SERP PBO although it does not take into consideration the SERP trust assets. The SERP is a non-qualified plan under the Employee Retirement Income Security Act guidelines and therefore, although funded annually to achieve 110% of the plan's accumulated benefit obligation, the trust assets of this plan are not included in the calculation of the funded status for accounting purposes. Central Hudson recognizes a regulatory liability or asset for the portion of the over or underfunded amount that is probable of return to or recovery from customers in future rates. The amounts reported as a component of other comprehensive income, net of tax, relate to a former Central Hudson officer who transferred to an affiliated company. The related amounts are charged to and reimbursed by the affiliated company.

Pension and OPEB benefit expenses are determined by actuarial valuations based on assumptions that Central Hudson evaluates annually. Central Hudson capitalizes a portion of the service cost component. The PSC has authorized deferral accounting treatment for any variations between actual Pension and OPEB expenses and the amount included in the current delivery rate structure.

Any unamortized balances related to net actuarial gains and losses, past service costs, and transitional obligations, which are recoverable from Central Hudson customers and would otherwise be recognized in accumulated other comprehensive income, are subject to deferral accounting treatment.

Central Hudson also sponsors a contributory 401(k) retirement plan ("401(k) plan") for its employees. The 401(k) plan provides for employee tax-deferred salary deductions for participating employees as well as employer contributions.

For more information see Note 12 – "Post-Employment Benefits".

Additionally, Central Hudson sponsors a contributory Deferred Compensation Plan ("Deferred Compensation Plan") for certain members of management and members of the Central Hudson Board of Directors. Although the Deferred Compensation Plan is a non-qualified plan, Central Hudson has established a trust for funding the associated liability to participants. For more information, see Note 17 – "Other Fair Value Measurements".

Equity-Based Compensation

Officers of CH Energy Group and Central Hudson were granted Share Unit Plan shares ("SUPs") under various plans as part of the officers' long-term incentives. Compensation expense and the related liability associated with the SUPs are recorded based on the fair value at each reporting date until settlement, reflecting expected future payout and time elapsed within the terms of the award, typically at the end of the three-year vesting period. The fair value of the SUPs' liability is based on Fortis' common share 5-day volume weighted average trading price at the end of each reporting period. CH Energy Group and Central Hudson have elected to recognize forfeitures when they occur due to the limited number of participants in the equity-based compensation plans. For more information, see Note 13 – "Equity-Based Compensation".

Common Stock Dividends

CH Energy Group's ability to pay dividends is affected by the ability of its subsidiaries to pay dividends. The Federal Power Act limits the payment of annual dividends by Central Hudson to its retained earnings. More restrictive is the PSC's limit on the dividends Central Hudson may pay to CH Energy Group. See Note 10 – "Capitalization-Common and Preferred Stock" for additional information. CH Energy Group's other subsidiaries do not have express restrictions on their ability to pay dividends.

Derivatives

From time to time, Central Hudson enters into derivative contracts in conjunction with the Company's enterprise risk management program to hedge certain risk exposures related to its business operations. Central Hudson uses derivative contracts to reduce the impact of volatility in the supply prices of natural gas and electricity and to hedge exposure to volatility in interest rates for its variable rate long-term debt. Central Hudson records all derivatives at fair value with certain exceptions including those derivatives that qualify for the normal purchase exception. The fair value of derivative instruments are estimates of the amounts that Central Hudson would receive or have to pay to terminate the outstanding contracts at the balance sheet dates. Unrealized gains and losses on Central Hudson's derivative contracts have no impact on earnings since the energy contracts are subject to regulatory deferral.

Realized gains and losses on Central Hudson's derivative instruments are returned to or recovered from customers through PSC-authorized deferral accounting mechanisms, with no material impact on cash flows, results of operations, or liquidity. Realized gains and losses on Central Hudson's energy derivative instruments and all associated costs are reported as part of purchased natural gas and purchased electricity in CH Energy Group's and Central Hudson's Statements of Income as the corresponding amounts are either recovered from or returned to customers through fuel cost adjustment mechanisms in revenues. See Note 16 – “Accounting for Derivative Instruments and Hedging Activities” for further details.

Normal Purchases and Normal Sales

Central Hudson enters into forward energy purchase contracts, including options, with counterparties that have generating capacity to support current load forecasts or counterparties that can meet Central Hudson’s load serving obligations. Central Hudson has elected the normal purchase exception for these contracts, which are not required to be measured at fair value and are accounted for on an accrual basis. See Note 14 – “Commitments and Contingencies” for further details.

Reclassification

Certain amounts shown in Note 4 – “Regulatory Matter” and Note 5 – “Income Tax” related to the prior year, have been reclassified to conform to the 2022 presentation. These reclassifications had no effect on the reported results of operations.

Recently Adopted Accounting Pronouncements

Income Taxes

Effective January 1, 2021, CH Energy Group and Central Hudson adopted Accounting Standards Update (“ASU”) No. 2019-12, *Simplifying the Accounting for Income Taxes*, which simplifies the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740, *Income Taxes*, related to the approach for intra-period tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. The new guidance also simplified aspects of the accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. CH Energy Group and its subsidiaries’ earnings, financial position, cash flows, and disclosures were not impacted by this adoption.

Note 2 - Revenues and Receivables

Central Hudson disaggregates revenue by segment (electric and natural gas operations) and by revenue type (revenue from contract with customers, alternative revenue programs, and other revenue).

Revenue from Contracts with Customers

Central Hudson records revenue as electricity and natural gas is delivered based on either the customers’ meter read or estimated usage for the month. For full-service customers, this includes delivery and supply of electricity and natural gas. For retail choice customers, this includes delivery only as these customers purchase supply from a retail marketer. Sales and usage-based taxes are excluded from revenues. Consideration received from customers on a billing schedule is not adjusted for the effect of a significant finance component because the period between a transfer of goods or services will be one year or less.

Alternative Revenues

Central Hudson’s alternative revenue programs include electric and natural gas RDMs, the electric and natural gas make whole provision, and lost finance charges, as established in the 2021 Rate Order, Gas Merchant Function Charge lost revenue, revenue requirement effect for incremental Leak Prone

Pipe ("LPP") miles replaced above the PSC targets and the revenue requirement effect for Gas Safety Ruling compliance. In addition, Central Hudson records alternative revenues related to Positive Revenue Adjustments ("PRA") and EAMs related to New York State clean energy goals, when prescribed targets are met.

Other Revenues

Other revenues consist of pole attachment rents, finance charges, miscellaneous fees, and other revenue adjustments. Included in other revenue adjustments are changes to regulatory deferral balances to reverse the impact of refunds (collections) of previously recognized deferrals and Negative Revenue Adjustments ("NRAs") pursuant to PSC Orders.

The following summary presents CH Energy Group's and Central Hudson's operating revenues disaggregated by segment and revenue source (In Thousands):

	Year Ended December 31,		
Electric	2022	2021	2020
Revenues from Contracts with Customers (ASC 606)	$ 787,340	$ 596,007	$ 547,586
Alternative Revenues (Non-ASC 606)	(2,967)	(10,887)	(18,268)
Other Revenue Adjustments (Non-ASC 606)	13,239	38,703	22,684
Total Operating Revenues Electric	$ 797,612	$ 623,823	$ 552,002
Natural Gas			
Revenues from Contracts with Customers (ASC 606)	$ 218,238	$ 170,233	$ 155,391
Alternative Revenues (Non-ASC 606)	7,394	8,484	9,281
Other Revenue Adjustments (Non-ASC 606)	(4,888)	(6,292)	(4,779)
Total Operating Revenues Natural Gas	$ 220,744	$ 172,425	$ 159,893

The year over year increase in electric and natural gas revenues from contracts with customers was primarily driven by higher billed purchased commodity costs. Further impacting these increases were higher delivery rates effective July 1, 2022, and higher surcharges when compared to 2021. The increases in billed purchased electric and natural gas do not impact earnings due to full deferral of commodity costs. However, these increases have contributed to increases in accounts receivable balances from customers, which is further discussed below.

The increase in electric and natural gas alternative revenue programs year over year is due to lower RDM deferral recorded for the difference between the actual billed revenues compared to the Rate Order prescribed targets. Also contributing to the increase in electric alternative revenue programs are higher incentives earned for achieving certain targets and milestones associated with energy efficiency programs.

The year over year decrease in other electric revenue adjustments is due to the lower amount refunded to customers for previously deferred revenues in excess of prescribed targets. Further impacting the year over year decrease are bill credits provided to customers in the first half of 2022 when compared to bill credits in 2021.

The year over year increase in other natural gas revenue adjustments is due to lower recovery for previously deferred revenues below prescribed targets, partially offset by lower gas bill credits in 2022 when compared to 2021.

Allowance for Uncollectible Accounts

Accounts receivable are recorded net of an allowance for uncollectible accounts based on the allowance for credit losses model. A summary of all changes in the allowance for uncollectible accounts receivable and accrued unbilled utility revenue balance is as follows (In Thousands):

	Year Ended December 31,	
	2022	2021
Balance at Beginning of Period	$ (11,200)	$ (10,400)
Uncollectible expense	(8,170)	(6,075)
Uncollectible write-off deferral	(4,130)	-
Uncollectible write-offs - net	12,300	5,275
Balance at End of Period	$ (11,200)	$ (11,200)

Accounts receivable balances from customers overall have continued to increase in the current period, not only in the current and 30-day past due categories, but also within arrears that are greater than 60 days past due. Growth in arrears began with the suspension of collection efforts required during COVID-19, which has impacted customers' payment behavior. This has been further compounded by increased commodity prices and higher seasonal winter energy usage in the first and fourth quarters. Management conducted quantitative and qualitative assessments of the allowance, including consideration of the differences in the current customers with arrears compared to past history, differences in payment behaviors of customers, including past economic factors impacting payment behavior compared to the current economic environment, as well as legislative and governmental actions taken to provide relief and assistance to customers financially impacted by the COVID-19 pandemic. Central Hudson continues to proactively contact customers regarding past due balances and to advise them of financial assistance programs available and is also working with local agencies and municipalities to obtain funding for its customers through federal and state programs. On June 16, 2022, the PSC approved Phase 1 of the AMP, in which residential utility customers who receive income-qualified government assistance for utility bills and other expenses and have past-due balances for service through May 1, 2022, will have those balances forgiven. For further details of this program see Note 4 – "Regulatory Matters-PSC Proceedings." On January 19, 2023, the PSC approved Phase 2 of the AMP providing arrears relief for certain residential and small commercial customers with arrears balances as of May 1, 2022, which were not eligible in Phase 1. The arrears amounts will be filed with Staff by February 18, 2023, together with Phase 2 Outreach and Education Plans. Central Hudson has begun collection efforts for certain customers with large arrears balances through communications, urging payment, and notifying customers that finance charges and termination efforts will be forthcoming. These efforts have generated some success with payments or payment arrangements. Central Hudson will continue its collections outreach, expanding the number of customers and commencing finance charges and termination efforts in 2023. Under the terms of the 2021 Rate Order, Central Hudson is authorized to defer bad debt write-offs if they exceed 10 basis points above the amounts billed to customers through delivery rates and applicable surcharges. For the year ended December 31, 2022, accounts written off as uncollectible exceeded the 10 basis points prescribed in rates and, as such, Central Hudson has deferred $4.1 million in uncollectible write-offs. Based on the analysis and taking all qualitative factors into consideration, the Company concluded that the reserve of $11.2 million should be maintained as of December 31, 2022. Clarity on Phase 2 AMP impacts, along with the continued collection efforts, particularly termination for non-payment, will provide visibility as to the timeframe over which the arrears growth will be resolved. The increase in arrears has resulted in a corresponding growth in working capital needs to support the business through additional borrowings as further discussed in Note 9 - "Short-Term Borrowing Arrangements" and Note 11 - "Capitalization - Long-Term Debt".

NOTE 3 – Utility Plant - Central Hudson

The following summarizes the type and amount of assets included in the electric, natural gas and common categories of Central Hudson's utility plant balances (In Thousands):

	Estimated Depreciable Life in Years	Utility Plant December 31, 2022	Utility Plant December 31, 2021
Electric:			
Production	25-95	$ 43,767	$ 43,719
Transmission	30-90	469,800	449,054
Distribution	8-80	1,247,465	1,187,608
Other	40	7,060	6,910
Total		$ 1,768,092	$ 1,687,291
Natural Gas:			
Transmission	19-85	$ 64,679	$ 63,284
Distribution	28-95	723,857	670,439
Other	N/A	442	442
Total		$ 788,978	$ 734,165
Common:			
Land and structures	50	$ 114,656	$ 113,200
Office and other equipment, radios, and tools	8-35	87,303	85,404
Transportation equipment	10-12	82,520	78,349
Other	3-15	164,317	149,017
Total		$ 448,796	$ 425,970
Gross Utility Plant		$ 3,005,866	$ 2,847,426

The borrowed component of funds used during construction and recorded as a reduction of interest expense was $2.9 million for the year ended December 31, 2022 and $1.5 million for each of the years ended December 31, 2021 and 2020. There was no equity component reported as other income for the year ended December 31, 2022 and $3.0 million for the years ended December 31, 2021, and 2020, respectively.

Included in the Net Utility Plant balance of $2.5 billion and $2.3 billion at December 31, 2022 and 2021 was $195.0 million and $181.0 million of intangible utility plant assets, comprised primarily of computer software costs, land, transmission, water, and other rights and the related accumulated amortization of $95.9 million and $78.5 million, respectively. Amortization expense for the years 2023-2027 is estimated to be $16.3 million, $13.1 million, $9.0 million, $7.2 million and $5.4 million, respectively.

As of December 31, 2022 and 2021, Central Hudson has reclassified from accumulated depreciation $47.4 million and $42.8 million, respectively, of cost of removal recovered through the rate-making process in excess of amounts incurred to date as a regulatory liability.

AROs for Central Hudson were approximately $3.1 million for the years ended December 31, 2022 and 2021. These amounts have been classified in the above chart under "Electric - Other" and "Common - Other" based on the nature of the ARO and are reflected as "Other - long-term liabilities" in the CH Energy Group and Central Hudson Balance Sheets.

NOTE 4 – Regulatory Matters

Summary of Regulatory Assets and Liabilities

Based on previous, existing or expected regulatory orders or decisions, the following table sets forth amounts that are expected to be recovered from or refunded to customers in future periods (In Thousands):

	December 31, 2022	December 31, 2021
Regulatory Assets:		
Deferred purchased electric costs (Note 1)	$ 43,490	$ 17,319
Deferred purchased natural gas costs (Note 1)	16,923	8,057
Deferred unrealized losses on derivatives - electric and natural gas (Note 16)	14,034	7,563
RAM - electric	16,109	15,258
RAM - natural gas	1,560	3,397
EAM - electric	7,140	3,570
RDM and carrying charges - electric	2,064	84 (2)
RDM and carrying charges - natural gas	4,511	2,942
Energy efficiency programs	28,829	16,819
Demand management programs	7,359	8,809
Deferred and accrued costs - SIR (Note 14)	71,436	76,032
Deferred storm costs	41,846	13,742
Deferred vacation pay accrual	9,010	9,753
Income taxes recoverable through future rates	42,704	35,784
Tax reform - unprotected impacts (Note 5)	23,733	23,733
Lost finance charge revenue	2,746	-
AMP and carrying charges	3,102	-
Uncollectible write-offs	4,130	-
Other	11,323 (1)	10,470 (1)(2)
Total Regulatory Assets	$ 352,049	$ 253,332
Less: Current Portion of Regulatory Assets	$ 125,980	$ 78,849
Total Long-term Regulatory Assets	$ 226,069	$ 174,483
Regulatory Liabilities:		
Rate moderator - electric	$ 16,376	$ 19,371
Rate moderator - natural gas	8,739	10,115
Deferred unrealized gains on derivatives - electric and natural gas (Note 16)	315	1,768
CEF and carrying charges	49,027	52,584
Tax reform - protected deferred tax liability (Note 5)	176,075	179,900
Deferred cost of removal (Note 3)	47,357	42,794
Deferred pension costs (Note 12)	74,898	90,934
Income taxes refundable through future rates	10,711	9,027
Deferred OPEB costs (Note 12)	24,652	31,032
Energy affordability program	4,428	5,289
Fast charging infrastructure program and carrying charges	5,516	5,455
NRAs	2,597	-
Deferred unbilled revenue	5,082	5,082
Utility asset sale to Transco	4,338	-
Other	7,227 (1)	4,626 (1)
Total Regulatory Liabilities	$ 437,338	$ 457,977
Less: Current Portion of Regulatory Liabilities	$ 75,053	$ 63,456
Total Long-term Regulatory Liabilities	$ 362,285	$ 394,521
Net Regulatory Liabilities	$ (85,289)	$ (204,645)

(1) Other includes estimated netting on the balance sheet of certain regulatory asset carrying charges to be offset against regulatory liabilities and collected through Rate Case offset/RAM.

(2) Certain amounts included in Other related to prior periods, have been reclassified to conform to the December 31, 2022 presentation.

The significant regulatory assets and liabilities include:

RAM: Mechanism prescribed in the 2018 Rate Order and continued in the 2021 Rate Order to recover from or refund to customers previously deferred balances related to major storms, energy efficiency programs, and environmental site investigation and remediation costs in excess of the three-year cumulative rate allowance, incentives earned, unencumbered NRAs, deferred property taxes and accrued carrying charges.

RDM and carrying charges: Mechanism prescribed in the 2018 Rate Order and continued in the 2021 Rate Order to recover from or refund to customers difference between actual revenues and forecasted revenues.

EAMs: Earnings adjustment mechanisms to be recovered from customers for incentives earned related to energy efficiency targets met as prescribed in the 2018 Rate Order and continued in the 2021 Rate Order.

Energy Efficiency Programs: This regulatory asset/liability represents amounts spent on Central Hudson's internally administered programs either below or in excess of amounts collected in rates.

Demand Management Programs: This regulatory asset represents deferred balances for costs incurred and incentives earned in excess of amounts collected related to Central Hudson's Non-Wires Alternative and Dynamic Load Management initiatives.

Deferred Storm Costs: Central Hudson's rates include a collection of funds for a major storm reserve, which are deferred as an offset against incremental costs incurred for major storm restoration. Incremental costs incurred in excess of the reserve funds are authorized to be collected via the RAM, to the extent sufficient.

Lost Finance Charge Revenue: This regulatory asset represents finance charge and reconnection fee revenues below the levels included in rates due to the impacts of the COVID-19 pandemic as prescribed in the 2021 Rate Order.

AMP and carrying charges: This regulatory asset represents the deferral of amounts credited to low-income customers, net of funding from New York State, which is being collected through a surcharge effective August 1, 2022, as approved by the PSC in the under Case 20-M-0479.

Uncollectible Write-Offs: This regulatory asset represents the deferral of uncollectible write-offs above levels included in rates as they exceeded the threshold prescribed in the 2021 Rate Order.

Deferred Vacation Pay Accrual: In accordance with Rate Order 84-2 a regulatory asset has been established to offset the accrued vacation liability since the accrued compensation is included in future allowable costs on an as paid basis and there is reasonable assurance of recovery.

Income Taxes Recoverable: This regulatory asset has been established to offset certain deferred tax liabilities because Central Hudson believes it is probable that they will be recoverable from customers.

Rate Moderator – Electric and Natural Gas: This regulatory liability balance represents the net balance after offset under the terms of the 2018 and 2021 Rate Orders, which were and will be used for future customer rate moderation, as well as deferred Danskammer Generating Station delivery revenues for future natural gas rate moderation.

CEF: This regulatory liability represents amounts collected from customers primarily under the CEF, the Renewable Portfolio Standards and System Benefit Charge (as prescribed in the CEF, 2018 and 2021

Rate Orders), in excess of amounts remitted to the New York State Energy Research and Development Authority ("NYSERDA") to fund its energy efficiency programs.

Income Taxes Refundable: This regulatory liability was established to offset certain deferred tax assets because Central Hudson believes it is probable that the related balances will be refundable to customers.

Energy Affordability Program: This regulatory liability represents deferred balances for amounts collected in excess of credits provided for energy affordability programs.

Net Plant and Depreciation Targets: This regulatory liability represents a deferral of the revenue requirement effect of net plant in service and depreciation expense below the defined targets as prescribed in the 2018 Rate Order.

Fast Charging Infrastructure Program and carrying charges: This regulatory liability represents amounts provided by NYSERDA and collected from customers to fund the fast-charging stations' annual incentive payments, as prescribed in the related Order.

Utility Asset Sale to Transco: This regulatory liability represents the gain on the sale of a utility asset to Transco, which has been deferred for the benefit of customers in accordance with Case 22-E-0077.

Deferred Unbilled Electric and Natural Gas Revenue: On July 20, 2016, the PSC issued the "Order Approving Accounting Change with Modification", allowing Central Hudson to realize unbilled revenue as revenue on the income statement, but required that $5.1 million of unbilled revenues remain as a regulatory liability.

In terms of the expected timing for recovery, regulatory asset balances reflect the following amounts (In Thousands):

	December 31,	
	2022	2021
Balances with offsetting accrued liability balances recoverable when future costs are actually incurred:		
Income taxes recoverable through future rates	$ 42,704	$ 35,784
Deferred unrealized losses on derivatives - electric	13,075	7,563
Deferred unrealized losses on derivatives - natural gas	959	-
Accrued SIR costs	69,832	71,653
Deferred ARO	823	583
Deferred vacation pay accrual	9,010	9,753
Other	-	404
	$ 136,403	$ 125,740
Balances earning a return via inclusion in rates and/or the application of carrying charges:		
Energy efficiency programs	$ 28,829	$ 16,819
Uncollectible write-offs	4,130	-
Deferred storm costs	41,846	13,742
Deferred SIR costs, net of recoveries	1,604	4,379
Deferred debt expense on re-acquired debt	1,246	1,508
Tax reform - unprotected impacts	23,733	23,733
Other	6,072	4,814
	$ 107,460	$ 64,995
Subject to current recovery:		
Deferred purchased electric costs	$ 43,490	$ 17,319
Deferred purchased natural gas costs	16,923	8,057
RAM - electric and natural gas	17,669	18,655
EAM - electric and natural gas	7,140	4,102
RDM - electric and natural gas	6,575	3,027

Demand management programs[1]	7,359	8,809
Lost finance charge revenue	2,746	-
AMP and carrying charges	3,102	-
Other	4,562	2,830
	$ 109,566	$ 62,799
Accumulated carrying charges:		
Carrying charges balancing	$ (1,380)	$ (218)
Other	-	16
	$ (1,380)	$ (202)
Total Regulatory Assets	$ 352,049	$ 253,332

(1) These amounts are subject to recovery over prescribed PSC timeframes unique to each program (most over 5 or 10 years). Balances subject to recovery over a period greater than 1 year are authorized to earn carrying charges at the pre-tax weighted average cost of capital.

PSC Proceedings

2018 Rate Order / 2021 Rate Order

The 2018 Rate Order was effective July 1, 2018, with Rate Year ("RY") 1 through 3, when used in connection with the 2018 Rate Order, defined as the twelve months ending June 30, 2019, June 30, 2020 and June 30, 2021, respectively.

On June 11, 2020, the Commission issued an Order Postponing Approved Electric and Gas Delivery Rate Increases, which approved Central Hudson's petition to ease the financial impact on customers during the critical months of the COVID-19 pandemic. The Order postponed, for three months, Central Hudson's approved RY3 electric and natural gas delivery rate increases scheduled to take effect on July 1 to October 1, 2020, with the forgone revenues recovered over the remaining nine months of the rate year ending June 30, 2021. The Order also stated that no carrying charges would be applied to the delayed recovery of these revenues and that Central Hudson would adjust the RDM targets to be consistent with the delayed electric and natural gas delivery rate increase implementation.

The 2021 Rate Order adopts the terms set forth in the August 24, 2021 Joint Proposal. The 2021 Rate Order also fully resolves all issues associated with the Sales Tax Refund Proceeding (Case 20-M-0134). The 2021 Rate Order was effective December 1, 2021 and includes a make-whole provision that provides new rates to become effective retroactive to July 1, 2021, with RY1, RY2, and RY3 defined as the twelve months ending June 30, 2022, June 30, 2023, and June 30, 2024, respectively.

A summary of the key terms of the 2018 and 2021 Rate Orders are as follows:

	2018 Rate Order (Dollars in Millions)			2021 Rate Order (Dollars in Millions)		
Description	RY1	RY2	RY3	RY1	RY2	RY3
Electric delivery rate increase/(decrease)	$19.7	$18.6	$25.1	($3.1)	$19.5	$20.7
Natural gas delivery rate increases	$6.7	$6.7	$8.2	$4.7	$6.3	$6.4
Return on equity	8.80%	8.80%	8.80%	9.00%	9.00%	9.00%
Earnings sharing	Yes[1]	Yes[1]	Yes[1]	Yes[2]	Yes[2]	Yes[2]
Capital structure – common equity	48%	49%	50%	50%	49%	48%
Bill credits/(surcharge) - electric	$6.0	$9.0	$11.0	($2.0)	$9.5	$21.5
Bill credits - natural gas	$3.5	$4.0	$4.0	$0.8	$3.2	$5.6
RDMs – electric and natural gas	Yes	Yes	Yes	Yes	Yes	Yes

(1) Return on equity ("ROE") > 9.3% and up to 9.8%, is shared 50% to customers, > 9.8% and up to 10.3%, is shared 80% to customers, and > 10.3% is shared 90% to customers.

(2) ROE > 9.5% and up to 10.0%, is shared 50% to customers, > 10.0% and up to 10.5%, is shared 75% to customers, and > 10.5% is shared 90% to customers.

The 2021 Rate Order utilizes existing regulatory balances to reduce bill impacts for customers during the term of the agreement. The 2021 Rate Order also reflects a postponement of certain capital projects, as well as reductions to operations and maintenance (“O&M”) costs to help manage customer bill impacts. The total electric revenue (decrease)/increase (after bill credits) is (0.2%), 1.2%, and 1.2% for RY1 through RY3, respectively and the total natural gas revenue increase (after bill credits) is 1.9%, 1.8%, and 1.8% for RY1 through RY3, respectively. The rate plan also includes an allowed ROE of 9.0% and an equity ratio of 50%, 49%, and 48% for RY1 through RY3, respectively.

The 2021 Rate Order:

- establishes the Company’s future energy infrastructure investments, programs, and operations;
- stabilizes electric delivery rates in the first year with a slight decrease for residential customers;
- reflects modest increases in gas delivery rates producing bill impacts just under two percent each RY;
- includes increased electric bill discounts for income qualified households and expanded access into Central Hudson’s Energy Affordability Program;
- reflects investments in clean energy efficiency ground and air-source electric heat pumps, electric vehicle charging, and system upgrades that support utilization of renewable sources;
- implements ten EAMs, which reflect a maximum earnings potential of 100 basis points;
- maintains the current Customer Average Interruption Duration Index (“CAIDI”) metric and reflects increasingly stringent System Average Interruption Frequency Index (“SAIFI”) targets, continues and further enhances existing gas safety performance metrics and public safety programs and includes higher performance requirements for Customer Service Performance Indicators with a net increase in total potential NRAs;
- provides Central Hudson with necessary resources to support ongoing O&M and necessary investments to reinforce electric and gas system reliability and resiliency through storm hardening, expanded vegetation management/tree trimming, continued investment for LPP replacement or elimination and deployment of new technologies, as well as information technology systems to further protect against cyber security risks; and
- includes several deferrals that provide the Company authorization to defer COVID-19 Incremental O&M Costs net of savings, lost revenues (finance charges and reconnection fee revenues), and uncollectible write-offs.

Central Hudson 2021 Financing Order

On November 18, 2021, the Commission approved the Company's request under Section 69 of the Public Service Law authorizing Central Hudson to enter into multi-year credit agreements in an aggregate amount not to exceed $250 million; and approval to issue and sell new long-term debt from time to time through December 31, 2024, in an aggregate amount not to exceed $445.7 million, including $412 million for traditional utility purposes and up to $33.7 million to refinance its variable interest debt. Central Hudson filed a letter indicating its unconditional acceptance of the November 18, 2021 Order on December 6, 2021.

FERC SDU Proceeding

On December 31, 2019, Central Hudson submitted to FERC a new rate schedule pursuant to Rate Schedule 12 of the NYISO OATT to establish a Facilities Charge for SDUs being installed on Central Hudson’s transmission facilities, which are required to provide four large generating facility developers with capacity resource interconnection service. This charge provides Central Hudson with full recovery of all reasonably incurred costs related to the development, construction, operation, and maintenance of the SDU and a reasonable return on its investment. Project costs to be recovered by Central Hudson and allocated to the Load Serving Entities (“LSEs”) pursuant to Rate Schedule 12 of the NYISO OATT are expected to be approximately $2.6 million plus operation, maintenance, and other applicable costs and will be updated annually. On October 4, 2021, the FERC approved an ROE of 9.4% plus a 50 basis point adder for a total ROE of 9.9% associated with this project.

August 2020 Tropical Storm Isaias

On August 5, 2020, the New York State Governor instituted proceeding 20-01633 directing the Commission to initiate an investigation of certain New York State utilities' responses to Tropical Storm Isaias, which impacted Central Hudson's service territory on August 4, 2020. On November 19, 2020, DPS issued an interim Storm Report setting forth preliminary findings, including purported failures by the identified utilities to comply with their respective Commission approved Emergency Response Plans and Show Cause ("Storm Show Cause Order") that initiated proceedings against Central Hudson and the other utilities. The Show Cause Order identified 32 apparent violations by Central Hudson, which, if established, could have resulted in up to $16 million of penalties. Central Hudson filed its response to the Show Cause Order on December 21, 2020. The Company performed a thorough investigation and, as indicated in its response, believed no penalty should be issued because the facts demonstrated that Central Hudson fully complied with its Commission-approved Emergency Response Plan, which served as the standard against which Central Hudson should be evaluated. On February 23, 2021, Central Hudson filed a Notice of Impending Settlement Negotiations. On July 7, 2021, Central Hudson and New York State DPS entered into a Settlement Agreement, which included a commitment by Central Hudson to establish a $1.5 million regulatory liability to be used by Central Hudson to support or advance storm restoration and/or electric system resiliency and reliability in excess of amounts funded by customers. The Commission approved the Settlement Agreement within the Order Granting Motion and Adopting Settlement Agreement on July 15, 2021. The Settlement Agreement does not include any finding or admission of any violation by Central Hudson and it specifies that the settlement amount is not a penalty. Central Hudson has fulfilled its obligation under the Settlement Agreement.

Energy Affordability & COVID-19 Proceeding

On June 11, 2020, the PSC established a new proceeding, Case 20-M-0266, to identify and address the effects of the COVID-19 pandemic on utility service in New York State, including all entities subject to PSC jurisdiction or permitting authority. The proceeding included, but is not limited to, impacts on rate-setting, rate design, utility financial strength, energy affordability programs, collections and termination of service ensuring the provision of safe and adequate service at just and reasonable rates in recognition of the ramifications from the COVID-19 pandemic, and the extent to which the PSC's clean energy programs should be maintained or accelerated.

On April 7, 2022, $250 million was approved in the New York State budget to provide funding for utility arrears relief for customers eligible for energy affordability programs. The Energy Affordability Policy ("EAP") Working Group developed and filed a report on May 23, 2022, which proposed a comprehensive arrears relief program for customers to be rolled out in two phases. Phase 1 would address all existing low-income customers' arrears and Phase 2 would be a broader program focused on arrears relief for residential customers that did not meet the definition of low-income, as well as some non-residential customers. On June 16, 2022, the PSC approved Phase 1 of the AMP, whereby residential utility customers who receive income-qualified government assistance for utility bills and other expenses and have past-due balances for service through May 1, 2022, will have those balances forgiven. The Phase 1 program was funded in part through the $250 million in New York State relief, $2.8 million of which was dispersed to Central Hudson. The remainder of the program cost is being recovered through a temporary surcharge on utility bills not to exceed a 0.5% bill impact for residential customers. As of December 1, 2022, Central Hudson had distributed approximately $7.1 million in relief via bill credits to roughly 5,600 eligible customers. Additional bill credits may be processed in early 2023 related to Phase 1 as new customers have the ability to become eligible for relief through the end of 2022.

On January 19, 2023, the PSC approved Phase 2 AMP providing arrears relief for certain residential and small commercial customers with arrears balances as of May 1, 2022, which were not eligible for Phase 1. The arrears amounts will be filed with Staff by February 18, 2023, together with the Phase 2 Outreach and Education Plans. The Company was directed to utilize deferred economic development balances to offset a portion of the program cost.

Customer Information System ("CIS") Show Cause Order

During the March 2022 PSC session, the PSC directed DPS Staff, and subsequently instituted Case 22-00666, to investigate billing issues subsequent to the implementation and to publicly track comments and other related documents. The Company has answered several data requests regarding the CIS implementation and continues to collaborate with DPS Staff. On December 15, 2022, the PSC issued its Order to Commence Proceeding and Show Cause ("CIS Show Cause Order"), under Case 22-M-0645. This Order discussed issues related to the CIS project, including system defects, training, testing, staffing, and cited alleged apparent violations of Public Service Law ("PSL"), New York Codes, Rules and Regulations, and prior PSC Orders. Central Hudson filed its response on January 17, 2023, acknowledging the unintended disruptive impact on customers, and stating that the Company did not violate the PSL, rules, or Commission Orders and neither penalties nor a prudence review is warranted. Central Hudson cited in its response its legal position that the Office of Investigations and Enforcement report misinterpreted, or misapplied specific sections of statutes, rules, and PSC Orders. The outcome of this investigation cannot be predicted at this time.

Agway Energy Services LLC ("Agway")

On February 25, 2022, Agway filed a Petition for Declaratory Ruling and Corrective Action Plan Concerning Failure of Central Hudson Gas and Electric Corporation to provide accurate Electronic Data Interchange information or provide accurate client bills ("Petition"). Agway is a licensed Energy Service Company that supplies energy for approximately 1,035 customers in Central Hudson's service territory. The Petition alleges impacts to Agway's business related to Central Hudson's billing system transition and alleges violations of the Uniform Billing Practices ("UBP") and that Central Hudson breached the Billing Services Agreement ("BSA"). Agway requested that the PSC investigate these issues, declare violations, order that Central Hudson resolve these violations in a timely manner, appoint an independent monitor to oversee the resolution, disgorge incurred fees, and award compensatory damages.

On March 18, 2022, Central Hudson filed its Verified Motion to Dismiss and Opposition to the Petition of Agway for a Declaratory Ruling ("Motion"). The Motion argues that the Petition should be dismissed because it is not a proper Petition for Declaratory Ruling because it fails to seek a PSC interpretation to a statute or rule and is deficient because it fails to allege a specific violation of either the UBP or BSA. Central Hudson's Motion also argues that it is improper for Agway to seek compensatory damages as damages are limited pursuant to the BSA and outside of the PSC's jurisdiction to provide. Agway has submitted a filing requesting to enter mediation on this matter, including recurring meetings with both parties and Department of Public Service ("DPS") Staff. On June 24, 2022, the Company entered mediation with Agway and continues to hold weekly meetings to discuss, investigate, and resolve issues.

Sale of Utility Asset to Transco

On June 21, 2022, the PSC issued Order Authorizing the Transfer of Transmission Property and Easement Interest under Case 22-E-0077. The Order was approved to increase the power transfer capability from upstate to downstate New York. In the Order, the PSC authorized the transfer of easement interest covering real property associated with a 12-mile overhead 115 kV electric transmission line ("SL Line") and certain transmission property and equipment related to the Sugarloaf Switching Station and the SL Line, from Central Hudson to New York Transco LLC and the recognition of any gains realized upon the transfer for the benefit of customers. On July 11, 2022, Central Hudson completed the sale of transmission property and easement interest for approximately $4.6 million with a realized gain of $4.4 million which was deferred as a regulatory liability for the benefit of customers with carrying charges at the Company's pre-tax weighted average cost of capital as prescribed by the Order.

NOTE 5 – Income Tax

Uncertain Tax Positions

In September of 2010, Central Hudson filed a request with the Internal Revenue Service ("IRS") to change its tax accounting method related to costs to repair and maintain utility assets. The change was effective for the tax year ended December 31, 2009. This change allows Central Hudson to take a current tax repair deduction for a significant amount of repair costs that were previously capitalized for tax purposes.

IRS guidance, with respect to repair deductions taken on Gas Transmission and Distribution repairs, is still pending. Therefore, tax reserves related to the gas repair deduction continue to be shown as "Tax Reserve" under the Deferred Credits and Other Liabilities section of the CH Energy Group and Central Hudson Balance Sheets.

Changes in the tax reserve reflect the ongoing uncertainty related to gas transmission and distribution repair deductions taken in the current period.

The following is a summary of CH Energy Group's and Central Hudson's activity related to the uncertain tax position (In Thousands):

	CH Energy Group Year Ended December 31, 2022	CH Energy Group Year Ended December 31, 2021	Central Hudson Year Ended December 31, 2022	Central Hudson Year Ended December 31, 2021
Unrecognized tax benefits balance, beginning of the period	$ 10,640	$ 9,164	$ 10,640	$ 9,146
Additions related to the current year	$ 1,336	$ 1,476	$ 1,336	$ 1,476
Decreases related to the prior year	$ (1,438)	$ -	$ (1,438)	$ -
Unrecognized tax benefits balance, end of the period	$ 10,538	$ 10,640	$ 10,538	$ 10,640
Offset per ASU No. 2013-11[(1)]	$ (10,538)	$ (10,640)	$ (10,538)	$ (10,640)
Tax reserve balance, end of the period	$ -	$ -	$ -	$ -

(1) Amounts are classified as a deferred tax asset per ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists.*

Income Tax Examinations

Jurisdiction	Tax Years Open for Audit
Federal	2019 – 2021
New York State	2019 – 2021

Components of Tax Reform Regulatory Balances

As a result of the Tax Cuts and Jobs Act, the Company was required to revalue its deferred tax assets and liabilities at the federal corporate income tax rate of 21%. Central Hudson recorded a regulatory liability due to the revaluation of plant related deferred tax liabilities, which are protected under tax normalization rules. The regulatory liability is adjusted monthly to reflect the amortization of the balance to the income statement under the tax normalization rules. The Company also recorded a regulatory asset due to the revaluation of all other deferred tax balances, which are not subject to the normalization rules.

The following is a summary of Central Hudson's activity in its regulatory liability balance related to the protected deferred tax liability (In Thousands):

	December 31, 2022	December 31, 2021
Protected Regulatory Liability, beginning of the period	$ 179,900	$ 183,915
Amortization of protected tax liability	(3,825)	(4,015)
Protected Regulatory Liability, end of the period	$ 176,075	$ 179,900

The following is a summary of Central Hudson's activity in its regulatory asset balance related to the unprotected impacts (In Thousands):

	December 31, 2022	December 31, 2021
Unprotected Regulatory Asset, beginning of the period	$ 23,733	$ 13,464
Change in unprotected tax asset	-	10,269
Unprotected Regulatory Asset, end of the period	$ 23,733	$ 23,733

The unprotected regulatory tax asset consisted of an excess deferred tax asset balance, which was partially offset by a regulatory liability resulting from the overcollection of tax from the effective date of the Tax Cuts and Jobs Act and the date delivery rates were reset. The increase of $10.3 million in 2021 resulted from the utilization of the overcollection for rate moderation per the 2021 Rate Order. The remaining excess deferred tax balance of $23.7 million will be addressed in the Company’s next rate case filing.

CARES Act

The CARES Act was signed into law on March 27, 2020. As permitted under the CARES Act, Central Hudson deferred payment of the employer share of the Social Security tax on its payroll during 2020. The deferred payroll tax was paid over two years; with half of the required amount paid by December 31, 2021 and the other half by December 31, 2022. There was no impact on earnings or on the effective tax rate resulting from the delayed payment of employer payroll tax under the CARES Act. As of December 31, 2021, the liability for the deferred payment of the employer’s portion of Social Security tax on payroll was $2.6 million reflected in “Other current liabilities” in the CH Energy Group and Central Hudson Balance Sheets, which was paid in December 2022.

New York State 2022 Budget Bill

On April 6, 2021, the New York State fiscal year 2022 budget bill was enacted. The budget bill included an increase in the corporate tax rate for businesses with taxable income over $5 million from 6.5% to 7.25% for tax years beginning on or after January 1, 2021 and before January 1, 2024 and extended the capital base tax, which was set to phase out in 2021. For tax years beginning on or after January 1, 2021 and before January 1, 2024, the business capital tax rate would be 0.1875% and would phase out for tax years beginning on and after January 1, 2024. CH Energy Group and Central Hudson have state net operating losses (“NOL”) that are expected to reduce taxable income below the $5 million threshold for the duration of the increased tax rate period and, therefore, that tax increase is not expected to have an impact on the Company’s earnings or cash flows. Both CH Energy Group and Central Hudson expect to be subject to the capital base tax during this period. For the years ended December 31, 2022 and 2021, Central Hudson recorded $1.8 million and $1.7 million of capital base tax, respectively. Capital base tax is included in “Taxes, other than income tax” in the CH Energy Group and Central

Hudson Statements of Income. The increase in capital base tax is included in the tax calculation used to set rates in the 2021 Rate Order.

Reconciliations

The following are reconciliations between the amount of federal income tax computed on income before taxes at the statutory rate and the amount reported in CH Energy Group's Consolidated Statement of Income and Central Hudson's Statement of Income (In Thousands):

CH Energy Group

	Year Ended December 31,		
	2022	2021	2020
Net income	$ 79,133	$ 73,953	$ 69,103
Current federal income tax expense (benefit)	64	(62)	(20)
Current state income tax (benefit) expense	(2)	225	100
Deferred federal income tax expense	15,334	11,897	9,930
Deferred state income tax expense	5,784	4,756	5,252
Income Before Income Taxes	$ 100,313	$ 90,769	$ 84,365
Computed federal tax at 21%	$ 21,066	$ 19,061	$ 17,717
State income tax net of federal tax benefit	4,568	3,935	4,224
Amortization of protected deferred tax liability[1]	(2,356)	(3,093)	(4,339)
Depreciation flow-through	349	(552)	(706)
Cost of removal	(2,348)	(2,220)	(1,926)
Other	(99)	(315)	292
Total Income Tax Expense	$ 21,180	$ 16,816	$ 15,262
Effective tax rate - federal	15.3%	13.0%	11.7%
Effective tax rate - state	5.8%	5.5%	6.4%
Effective Tax Rate - Combined	21.1%	18.5%	18.1%

[1] Under normalization rules, plant-related deferred taxes reverse at the same rate as the original deferral.

Central Hudson

	Year Ended December 31,		
	2022	2021	2020
Net income	$ 78,092	$ 73,623	$ 69,141
Current federal income tax benefit	(10)	-	(18)
Deferred federal income tax expense	14,988	11,313	9,952
Deferred state income tax expense	5,553	4,795	5,211
Income Before Income Taxes	$ 98,623	$ 89,731	$ 84,286
Computed federal tax at 21%	$ 20,711	$ 18,844	$ 17,700
State income tax net of federal tax benefit	4,387	3,788	4,117
Amortization of protected deferred tax liability[1]	(2,356)	(3,093)	(4,339)
Depreciation flow-through	349	(552)	(706)
Cost of removal	(2,348)	(2,220)	(1,926)
Other	(212)	(659)	299
Total Income Tax Expense	$ 20,531	$ 16,108	$ 15,145
Effective tax rate - federal	15.2%	12.6%	11.8%
Effective tax rate - state	5.6%	5.4%	6.2%
Effective Tax Rate - Combined	20.8%	18.0%	18.0%

[1] Under normalization rules, plant-related deferred taxes reverse at the same rate as the original deferral.

For the years ended December 31, 2022, 2021, and 2020, the combined effective tax rate for CH Energy Group and Central Hudson is lower than the combined statutory rate due to tax normalization rules and the timing of flow through tax items related to capital expenditures. For the year ending December 31, 2022, the increase in the effective tax rate in relation to the comparable prior periods is driven by higher income before taxes, which is subject to the statutory rate and unrealized book losses excluded for tax purposes.

The following is a summary of the components of deferred taxes as reported in CH Energy Group's Consolidated Balance Sheets (In Thousands):

	December 31, 2022	December 31, 2021
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 6,603	$ 3,300
Federal R&D credit carryforward (1)	1,058	840
Plant-related	-	2,712
Tax reform - protected deferred tax liability	46,606	47,468
Pension costs	-	1,539
Income taxes refundable through future rates	10,711	9,027
Federal NOL carryforwards	28,504	10,595
New York State NOL carryforwards, net of federal benefit (1)	12,854	7,263
CEF	5,075	9,192
Rate moderator	6,564	7,706
Contributions in aid of construction	10,154	9,407
Directors and officers deferred compensation	13,263	15,102
Deferred payroll taxes	-	680
Cost of removal	6,209	946
Utility asset sale to Transco	1,134	-
R&D credit	696	-
Fast charging infrastructure	1,442	1,426
SIR costs and recovery	637	-
Energy affordability program	1,134	1,671
Other (1)	1,932	3,748
Accumulated Deferred Income Tax Asset	$ 154,576	$ 132,622
Accumulated Deferred Income Tax Liability:		
Depreciation	$ 273,857	$ 259,986
Repair allowance	3,718	3,927
Repair deduction	120,815	104,519
EAM (1)	1,862	1,072
OPEB (1)	2,073	150
Income taxes recoverable through future rates	21,030	17,269
Tax reform - unprotected deferred tax asset	6,203	6,203
Deferred SIR costs	-	1,144
RDM	1,718	790
Demand management programs	1,923	2,301
Purchased electric costs	11,366	4,526
Purchased natural gas costs	4,423	2,106
Storm costs	10,936	3,591
RAM	4,618	4,875
Transco investment (1)	1,735	1,641
Other (1)	4,660	4,521

Accumulated Deferred Income Tax Liability	$ 470,937	$ 418,621
Net Deferred Income Tax Liability	$ 316,361	$ 285,999

(1) Certain amounts included in Other related to prior periods, have been reclassified to conform to the December 31, 2022 presentation.

The following is a summary of the components of deferred taxes as reported in Central Hudson's Balance Sheet (In Thousands):

	December 31, 2022	2021
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 6,603	$ 3,300
Federal R&D credit carryforward (1)	1,058	840
Plant-related	-	2,712
Tax reform - protected deferred tax liability	47,048	47,828
Pension costs	-	1,539
Income taxes refundable through future rates	10,711	9,027
Federal NOL carryforwards	28,866	11,327
New York State NOL carryforwards, net of federal benefit (1)	12,989	7,330
CEF	5,075	9,192
Rate moderator	6,564	7,706
SIR cost and recovery	637	-
Contributions in aid of construction	10,154	9,407
Directors and officers deferred compensation	12,932	13,902
Cost of removal	6,209	946
Fast charging infrastructure	1,442	1,426
Deferred payroll taxes	-	680
Energy affordability program	1,134	1,671
Utility asset sale to Transco	1,134	-
Research and development credit	696	-
Other (1)	1,586	3,403
Accumulated Deferred Income Tax Asset	$ 154,838	$ 132,236
Accumulated Deferred Income Tax Liability:		
Depreciation	$ 273,555	$ 259,624
Repair allowance	3,718	3,927
Repair deduction	120,815	104,519
EAM (1)	1,862	1,072
OPEB (1)	2,073	150
Income taxes recoverable through future rates	21,030	17,269
Tax reform - unprotected deferred tax asset	6,203	6,203
Deferred SIR costs	-	1,144
RDM	1,718	790
Demand management programs	1,923	2,301
Purchased electric costs	11,366	4,526
Purchased natural gas costs	4,423	2,106
Storm costs	10,936	3,591
RAM	4,618	4,875
Other (1)	5,199	5,014
Accumulated Deferred Income Tax Liability	$ 469,439	$ 417,111
Net Deferred Income Tax Liability	$ 314,601	$ 284,875

(1) Certain amounts included in Other related to prior periods, have been reclassified to conform to the December 31, 2022 presentation.

NOTE 6 – Investments in Unconsolidated Affiliates

In April 2019, National Grid and Transco were awarded the Segment B portion of one of their proposals related to the Alternating Current Transmission Order with NYISO for a transmission project that will improve the flow of power from upstate renewable resources to meet downstate demand and enhance the reliability and resilience of the grid ("AC Project"). Transco is authorized to earn a return on equity invested in the project (up to 53% of the project cost) of 9.65%, with up to an additional 1% available for incentives. The project has an estimated cost of $600 million plus interconnection costs and CHET's equity funding requirement of this cost as a 6.1% owner of this project in Transco is expected to be $19.4 million. As of December 31, 2022, CHET has made capital contributions of $16.5 million to Transco to fund a portion of the Segment B project costs. At December 31, 2022 and 2021, CHET's investment in Transco was approximately $23.5 million and $15.0 million, respectively.

In November 2018, the Transco limited liability company agreement was amended ("Transco Amendment") to allow Transco to pursue additional projects that might result from future NYISO Public Policy Transmission Planning Processes ("PPTP Processes"). Under the Transco Amendment, CHET would have a 10% ownership stake in transmission solutions related to future projects that result from future PPTP Processes. CHET would also be allocated 10% of future development costs for any new transmission projects as part of future PPTP Processes. In response to a Long Island Offshore Wind Export Public Policy Transmission Need Project Solicitation issued by the NYISO on August 12, 2021, Transco, partnering with the New York Power Authority ("NYPA"), submitted to NYISO on October 11, 2021, four separate proposed solutions to upgrade existing transmission facilities on Long Island to accommodate 3,000 MWs of anticipated offshore wind generated electricity while also proposing three alternative expansion solutions. Three unrelated developers proposed 12 other solutions. NYISO's response to the solicitation proposals, including the Transco-NYPA proposals, is expected to be issued in the first half of 2023. In the event that a Transco-NYPA proposal is accepted by NYISO, CHET would own and fund the equity investment associated with Transco's portion of the project.

During the first quarter of 2022, CHEC received a final distribution from one of its remaining investments following termination of the partnership. The value of CHEC's equity investments was $0.0 and $0.2 million at December 31, 2022 and 2021, respectively.

NOTE 7 – Research and Development

Central Hudson's R&D expenditures were $3.6 million in 2022, $4.1 million in 2021, and $3.7 million in 2020. These expenditures were for internal research programs and for contributions to research administered by NYSERDA, the Electric Power Research Institute and other industry organizations.

NOTE 8 – Leases

At December 31, 2022, CH Energy Group did not have any leases other than leases from Central Hudson. Central Hudson's leasing activities accounted for as operating leases include office facilities and equipment with remaining terms of approximately one to eight years and communication tower space with remaining terms of approximately three to 18 years including options to renew existing leases for an additional 10 to 15 years. Most leases include one or more options to renew, with renewal terms that may extend the lease term from 15 to 20 years. Certain lease agreements include periodic escalation clauses based on an index or fixed rate or require Central Hudson to pay real estate taxes, insurance, maintenance, or other operating expenses associated with the lease premises.

The following table details supplemental balance sheet information related to CH Energy Group and Central Hudson's operating leases (In Thousands):

Leases	Classification	December 31, 2022	December 31, 2021
Operating Lease Assets	Other Assets	$ 3,082	$ 3,488
Current operating lease liabilities	Other Current Liabilities	$ 470	$ 433
Noncurrent operating lease liabilities	Other Liabilities	2,759	3,155
Total Lease Liabilities		$ 3,229	$ 3,588

Operating and variable lease costs, as well as short-term lease cost for the years ended December 31, 2022, 2021, and 2020, were not material to CH Energy Group or Central Hudson's results of operations.

As of December 31, 2022, CH Energy Group and Central Hudson had the following minimum future maturities of operating lease liabilities (In Thousands):

Year Ending December 31,	Operating Leases
2023	$ 564
2024	525
2025	469
2026	422
2027	414
Thereafter	1,294
Total Lease Payments	$ 3,688
Less: imputed interest	459
Total Lease Liabilities	$ 3,229
Less: current portion	470
Total Non-Current Lease Liabilities	$ 2,759

The following table includes supplemental information related to CH Energy Group and Central Hudson's operating leases:

	December 31, 2022	December 31, 2021
Weighted-Average Remaining Lease Term (years)	9	8.4
Weighted-Average Discount Rate	3.10%	3.11%

NOTE 9 – Short-Term Borrowing Arrangements

Committed Credit Facilities

On April 4, 2022, Central Hudson entered into a first amendment increasing lender supplement to the March 2020 Central Hudson credit agreement with five commercial banks. The amendment replaces LIBOR with a benchmark replacement interest rate and increases the aggregate commitment by the lenders by $50 million, making the aggregate amount of total commitments equal to $250 million. The credit agreement as amended has a five-year term, maturing in March 2025. Proceeds received from the revolving credit agreement are used for working capital needs and for general corporate purposes. Letters of credit are available up to $15 million from three participating banks.

The Central Hudson credit agreement includes a covenant that its total funded debt to total capital will not exceed 0.65 to 1.00. The credit agreement is also subject to certain restrictions and conditions, including that there will be no event of default and, subject to certain exceptions, that Central Hudson will not sell, lien or otherwise encumber its assets or enter into certain transactions including certain transactions with affiliates. Central Hudson is also required to pay a commitment fee calculated at a rate based on the applicable Standard and Poor's or Moody's rating on the average daily unused portion of the credit facility. At December 31, 2022, Central Hudson was in compliance with all financial debt covenants.

Uncommitted Credit

At December 31, 2022, CH Energy Group and Central Hudson had $10 million and $60 million respectively, in uncommitted short-term credit arrangements with four commercial banks totaling $70 million. Proceeds from these credit arrangements are used to diversify cash sources and provide competitive options to minimize Central Hudson's cost of short-term debt.

On November 4, 2022, CH Energy Group entered into a $10 million, short-term uncommitted credit agreement with a commercial bank to provide liquidity to meet short term cash needs.

On December 15, 2022, Central Hudson entered into a $30 million, short-term uncommitted credit agreement with a commercial bank not included in its current credit facility to provide additional liquidity to its existing portfolio. Proceeds received from the new credit agreement are to be used for working capital needs and general corporate purposes.

At December 31, 2021, there were no short-term credit arrangements for CH Energy Group. Central Hudson had uncommitted short-term credit arrangements with two commercial banks totaling $30 million.

Balances outstanding under the various credit arrangements are as follows (Dollars in Thousands):

	CH Energy Group		Central Hudson	
	December 31, 2022	December 31, 2021	December 31, 2022	December 31, 2021
Committed Credit	$ 90,000	$ 100,000	$ 90,000	$ 100,000
Uncommitted Credit	15,000	7,000	15,000	7,000
Total	$ 105,000	$ 107,000	$ 105,000	$ 107,000
Weighted Average Interest Rate	5.17%	0.99%	5.17%	0.99%

NOTE 10 – Capitalization – Common and Preferred Stock

Capital Contributions

During 2022, CH Energy Group received capital contributions of $54.3 million from its parent FortisUS. Additionally, during 2022, Central Hudson received capital contributions of $46.0 million from its parent CH Energy Group and CHET received capital contributions of $7.9 million from its parent CH Energy Group in order to fund capital expenditures related to the Transco AC Project.

During 2021, CH Energy Group received a contribution of approximately $5.0 million under the tax sharing agreement with its parent FortisUS. Additionally, during 2021, CH Energy Group received capital contributions of $4.4 million from FortisUS and Central Hudson received a capital contribution of

$6.0 million from its parent company CH Energy Group. During 2021, CHET received capital contributions of $4.0 million from its parent CH Energy Group in order to fund capital expenditures related to the Transco AC Project.

During 2020, CH Energy Group received capital contributions of $15.0 million from its parent FortisUS and Central Hudson received capital contributions of $12.0 million from its parent company CH Energy Group. Additionally, during 2020, CHET received a $0.3 million capital contribution from its parent CH Energy Group.

These contributions were recorded as paid in capital, see CH Energy Group's and Central Hudson's Consolidated Statements of Equity.

Common Stock Dividends

CH Energy Group's ability to pay dividends is affected by the ability of its subsidiaries to pay dividends. The Federal Power Act limits the payment of annual dividends by Central Hudson to its retained earnings. More restrictive is the PSC's limit on the dividends Central Hudson may pay to CH Energy Group, which is 100% of the average annual income available for common stock, calculated on a two-year rolling average basis. Based on this calculation, Central Hudson was restricted to a maximum annual payment of $76.0 million, $71.0 million, and $67.0 million in dividends to CH Energy Group for the periods ended December 31, 2022, 2021, and 2020, respectively. Central Hudson's ability to pay dividends would be reduced to 75% of its average annual income in the event of a downgrade of its senior debt rating below "BBB+" by more than one rating agency, if the stated reason for the downgrade is related to any of CH Energy Group's or Central Hudson's affiliates. Further restrictions are imposed for rating downgrades below this level. In addition, Central Hudson would not be allowed to pay dividends if its average common equity ratio for the 13 months prior to a proposed dividend was more than 200 basis points below the ratio used in setting rates. CH Energy Group's other subsidiaries do not have express restrictions on their ability to pay dividends.

During 2022, 2021, and 2020 CH Energy Group did not pay any dividends to FortisUS, the sole shareholder of CH Energy Group.

Central Hudson did not pay any dividends to its parent CH Energy Group in 2022, 2021, and 2020.

During 2022, CHET paid dividends to its parent CH Energy Group of $1.0 million. CHET did not pay dividends to its parent CH Energy Group during 2021 and 2020.

CHEC did not pay any dividends to its parent CH Energy Group during 2022. CHEC paid dividends of $1.0 million to its parent CH Energy Group in 2021. CHEC did not pay any dividends to its parent CH Energy Group during 2020.

Preferred Stock

Other than one share of Junior Preferred Stock, Central Hudson had no outstanding preferred stock as of December 31, 2022 and 2021.

NOTE 11 – Capitalization – Long-Term Debt

The majority of the long-term debt instruments are redeemable at the discretion of CH Energy Group and Central Hudson, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

A summary of CH Energy Group's and Central Hudson's long-term debt is as follows (In Thousands):

Series	Maturity Date	December 31, 2022 Principal	December 31, 2022 Unamortized Debt Issuance Costs	December 31, 2021 Principal	December 31, 2021 Unamortized Debt Issuance Costs
Central Hudson:					
Promissory Notes:					
2006 Series E (5.76%)[4]	Nov. 17, 2031	$ 27,000	$ 153	$ 27,000	$ 171
1999 Series B[1],[2]	Jul. 01, 2034	33,700	199	33,700	216
2005 Series E (5.84%)[4]	Dec. 05, 2035	24,000	129	24,000	139
2007 Series F (5.804%)[5]	Mar. 23, 2037	33,000	197	33,000	211
2009 Series F (5.80%)[5]	Nov. 01, 2039	24,000	183	24,000	193
2010 Series B (5.64%)[6]	Sep. 21, 2040	24,000	89	24,000	94
2010 Series G (5.716%)[6]	Apr. 01, 2041	30,000	188	30,000	199
2011 Series G (3.378%)[6]	Apr. 01, 2022	-	-	23,400	7
2011 Series G (4.707%)[6]	Apr. 01, 2042	10,000	83	10,000	88
2012 Series G (4.776%)[6]	Apr. 01, 2042	48,000	408	48,000	429
2012 Series G (4.065%)[6]	Oct. 01, 2042	24,000	246	24,000	259
2013 Series D (4.09%)[7]	Dec. 2, 2028	16,700	62	16,700	72
2014 Series E [7],[11]	Mar. 26, 2024	30,000	24	30,000	45
2015 Series F (2.98%)[7]	Mar. 31, 2025	20,000	35	20,000	51
2016 Series H (2.56%)[8]	Oct. 28, 2026	10,000	35	10,000	44
2016 Series I (3.63%)[8]	Oct. 28, 2046	20,000	112	20,000	117
2017 Series J (4.05%)[8]	Aug. 31, 2047	30,000	158	30,000	164
2017 Series K (4.20%)[8]	Aug. 31, 2057	30,000	166	30,000	171
2018 Series L (4.27%)[8]	Jun. 15, 2048	25,000	162	25,000	169
2018 Series M (3.99%)[8]	Oct. 28, 2026	40,000	117	40,000	149
2018 Series N (4.21%)[8]	Oct. 28, 2033	40,000	179	40,000	196
2019 Series O (3.89%)[9]	Oct. 28, 2049	50,000	250	50,000	259
2019 Series P (3.99%)[9]	Oct. 28, 2059	50,000	257	50,000	264
2020 Series Q (3.42%)[9]	May 14 2050	30,000	160	30,000	166
2020 Series R (3.62%)[9]	Jul. 14, 2060	30,000	165	30,000	169
2020 Series S (2.03%)[9]	Sep. 28, 2030	40,000	169	40,000	192
2020 Series T (2.03%)[9]	Nov. 17, 2030	30,000	139	30,000	157
2021 Series U (3.29%)[9]	Mar. 16, 2051	75,000	392	75,000	406
2021 Series V (3.22%)[9]	Oct. 30, 2051	55,000	295	55,000	305
2022 Series W (2.37%)[10]	Jan. 27, 2027	50,000	215	-	-
2022 Series X (2.59%)[10]	Jan. 27, 2029	60,000	273	-	-
2022 Series Y (5.07%)[10]	Sept. 28, 2032	100,000	504	-	-
2022 Series Z (5.42%)[10]	Sept. 28, 2052	10,000	66	-	-
Total Central Hudson		$ 1,119,400	$ 5,810	$ 922,800	$ 5,102
Less: current portion of long-term debt		-		(23,400)	
Central Hudson Net Long-term Debt		$ 1,119,400		$ 899,400	
CH Energy Group:					
Promissory Notes:					
2009 Series B (6.80%)[3]	Dec. 15, 2025	$ 6,746	$ 28	$ 8,710	$ 37
Less: current portion of long-term debt		(2,100)		(1,964)	
CH Energy Group Net Long-term Debt		$ 1,124,046	$ 5,838	$ 906,146	$ 5,139

(1) Promissory Notes issued in connection with the sale by NYSERDA of tax-exempt pollution control revenue bonds.
(2) Variable (auction) rate notes.
(3) The maturity date represents the final repayment date, principal repayments are due semi-annually.
(4) Issued pursuant to a 2004 PSC Order approving the issuance by Central Hudson prior to December 31, 2006, of up to $85 million of unsecured medium-term notes.
(5) Issued pursuant to a 2006 PSC Order approving the issuance by Central Hudson prior to December 31, 2009, of up to $120 million of unsecured medium-term notes.
(6) Issued pursuant to a 2009 PSC Order approving the issuance by Central Hudson prior to December 31, 2012, of up to $250 million of unsecured medium-term notes or other forms of long-term indebtedness.
(7) Issued pursuant to a 2012 PSC Order approving the issuance by Central Hudson prior to December 31, 2015, of up to $250 million of unsecured medium-term notes or other forms of long-term indebtedness.

(8) Issued pursuant to a 2015 PSC Order approving the issuance by Central Hudson prior to December 31, 2018, of up to $350 million of unsecured medium-term notes or other forms of long-term indebtedness.
(9) Issued pursuant to a 2018 PSC Order approving the issuance by Central Hudson prior to December 31, 2021, of up to $425 million of unsecured medium-term notes or other forms of long-term indebtedness.
(10) Issued pursuant to a 2021 PSC Order approving the issuance by Central Hudson prior to December 31, 2024, of up to $412 million of unsecured medium-term notes or other forms of long-term indebtedness.
(11) Variable rate notes.

On January 27, 2022, Central Hudson issued $50 million of Series W, 5-year Senior Notes with an interest rate of 2.37% per annum and a maturity date of January 27, 2027 and $60 million of Series X, 7-year Senior Notes with an interest rate of 2.59% per annum and a maturity date of January 27, 2029. On September 28, 2022, Central Hudson issued $100 million of Series Y, 10-year Senior Notes with an interest rate of 5.07% per annum and a maturity date of September 28, 2032 and $10 million of Series Z, 30-year Senior Notes with an interest rate of 5.42% per annum and a maturity date of September 28, 2052. Central Hudson used the proceeds from the sale of the Senior Notes for general corporate purposes, including the repayment of $23.4 million of maturing debt on April 1, 2022 and the repayment of short-term borrowings.

During 2021, Central Hudson issued $130 million of unsecured Senior Notes, with various interest rates and maturities of 30 years. Central Hudson used the proceeds from the sale of the Senior Notes to repay $44.2 million of maturing debt and for general corporate purposes, including the repayment of short-term borrowings.

At December 31, 2022, Central Hudson had $30 million of 2014 Series E 10-year notes with a floating interest rate of 3-month LIBOR plus 1%. To mitigate the potential cash flow impact from unexpected increases in short-term interest rates, Central Hudson purchased a four-year interest rate cap that will expire on March 26, 2024. The rate cap has a notional amount equal to the outstanding principal amount of the 2014 Series E notes and is based on the quarterly reset of the LIBOR rate on the quarterly interest payment dates. Central Hudson would receive a payout if the LIBOR rate exceeds 3% at the start of any quarterly interest period during the term of the cap. Central Hudson received an immaterial payout during the year ended December 31, 2022. There were no payouts on these interest rate caps during the year ended December 31, 2021.

The principal amount of Central Hudson’s outstanding 1999 Series B NYSERDA Bonds totaled $33.7 million at December 31, 2022. These are tax-exempt multi-modal bonds that are currently in a variable rate mode and mature in 2034. To mitigate the potential cash flow impact from unexpected increases in short-term interest rates on Series B NYSERDA Bonds, Central Hudson purchased a three-year interest rate cap, which expired on April 1, 2022. The rate cap had a notional amount equal to the outstanding principal amount of the Series B bonds and was based on the monthly weighted average of an index of tax-exempt variable rate debt, multiplied by 175%. Central Hudson would receive a payout if the adjusted index exceeded 4% for a given month. There were no payouts on these interest rate caps in 2021. During 2022, Central Hudson purchased a one-year interest rate cap. The rate cap has a notional amount equal to the outstanding principal amount of the Series B bonds and expires on April 1, 2023. The cap is based on the monthly weighted average of Securities Industry and Financial Markets Association (“SIFMA”) index, multiplied by 1.75. Central Hudson would receive a payout if the adjusted index exceeds 5% for a given month. During the fourth quarter of 2022, following Federal Reserve interest rate increases during the year, the adjusted SIFMA rate index exceeded the 5% cap. As a result, Central Hudson received an immaterial payout during the year ended December 31, 2022.

See Note 16 – “Accounting for Derivative Instruments and Hedging Activities” for fair value disclosures related to these interest rate cap agreements.

In its 2021 Rate Order, the PSC extended the continued deferral accounting treatment for variations in the interest costs of the 1999 Series B NYSERDA Bonds and the Series E 10-year notes. As such, variations between the actual interest rates on these bonds and the interest rate included in the current delivery rate structure for these bonds are deferred for future recovery from or refund to customers and therefore do not impact earnings. The regulatory asset or liability related to the variable rate note is included in the “other” category, See Note 4 – “Regulatory Matters”.

Long-Term Debt Maturities

See Note 17 – “Other Fair Value Measurements” for a schedule of long-term debt maturing or to be redeemed during the next five years and thereafter.

Financing Petition

By Order issued and effective November 22, 2021, the PSC authorized Central Hudson to enter into multi-year credit agreements in an aggregate amount not to exceed $250 million; and to issue and sell new long-term debt in an aggregate amount not to exceed $412 million through December 2024. The Order also allows Central Hudson to refinance $33.7 million of existing variable debt obligations prior to December 31, 2024. The approval to issue and sell up to $412 million of long-term debt provides Central Hudson with additional means to fund operational needs, continued capital investments, and repay maturing debt.

Debt Covenants

CH Energy Group’s $6.8 million of privately placed notes require compliance with certain covenants including maintaining a ratio of total consolidated debt to total consolidated capitalization of no more than 0.65 to 1.00 and not permitting certain debt, other than the privately placed notes, associated with the unregulated operations of CH Energy Group to exceed 10% of total consolidated assets.

Central Hudson, under the terms of the various note purchase agreements, is subject to similar financial covenants and restrictions to those of CH Energy Group, including restrictions with respect to Central Hudson’s indebtedness and assets. As of December 31, 2022, CH Energy Group and Central Hudson were in compliance with all covenants.

NOTE 12 – Post-Employment Benefits

In its Orders, the PSC has authorized deferral accounting treatment for any variations between actual Pension and OPEB expense, and the amount included in the current delivery rate structure. As a result, variations in expenses for post-employment benefit plans at Central Hudson do not have any impact on earnings.

Pension Benefits

Central Hudson has a non-contributory Retirement Plan covering substantially all of its employees hired before January 1, 2008 and a non-qualified SERP for certain executives. The Retirement Plan is a defined benefit plan, which provides pension benefits based on an employee’s compensation and years of service. In 2007, Central Hudson amended the Retirement Plan to eliminate these benefits for managerial, professional, and supervisory employees hired on or after January 1, 2008. The Retirement Plan for unionized employees was similarly amended for all employees hired on or after May 1, 2008. As of December 31, 2022, 28% of all active employees were eligible to participate in the Retirement Plan. The Retirement Plan’s assets are held in a trust fund. Central Hudson has provided periodic updates to the benefit formulas stated in the Retirement Plan.

Central Hudson’s funded status for Pension benefits was $57.8 million at December 31, 2022 and $68.7 million at December 31, 2021. The fluctuation in Central Hudson’s prefunded status of approximately $10.9 million was the result of a decrease in the plan assets of approximately $220.4 million, partially offset by the decrease of $209.5 million in PBO liabilities. The decrease in plan assets was driven by investment losses and the decrease in liabilities was primarily driven by an increase in the discount rate.

The funded status includes the difference between the PBO for the Retirement Plan and the market value of the pension assets, net of any liability for the non-qualified SERP. The funded status does not reflect approximately $39.7 million and $40.1 million of SERP trust assets at December 31, 2022 and 2021.

The cumulative amount of net periodic benefit cost in excess of employer contributions at December 31, 2022 and December 31, 2021 was $9.6 million and $26.1 million, respectively. This does not include any cumulative contributions to the SERP as it is a non-qualified plan.

The difference between these amounts and the prefunded assets, totaling $67.3 million at December 31, 2022 and $94.8 million at December 31, 2021, represents the required funded status adjustment and will be recognized in Central Hudson's future expense. Gains or losses and prior service costs or credits that arise during the period, but that are not recognized as components of net periodic pension cost, would typically be recognized as a component of other comprehensive income ("OCI"), net of tax. However, Central Hudson has PSC approval to record regulatory assets or liabilities rather than adjusting comprehensive income to offset the funding status adjustment for amounts recoverable from customers in future rates. Therefore, these funded status adjustments have been recorded as a regulatory asset for the portion recoverable from Central Hudson customers in accordance with the 1993 PSC Policy and as OCI for the portion, net of tax, that relates to a former Central Hudson officer who transferred to an affiliated company. These amounts reported as OCI are charged to and reimbursed by the affiliated company.

The funded status of Central Hudson's pension costs is as follows (In Thousands):

	December 31, 2022(1)(2)	December 31, 2021(1)(2)
Prefunded pension costs	$ 57,769	$ 68,728

(1) Includes approximately $0.2 million at December 31, 2022 and December 31, 2021 of accrued pension liability recorded at CH Energy Group as a result of the resignation in 2014 of a CH Energy Group officer with a change in control agreement.

(2) Includes approximately $1.6 million and $1.5 million at December 31, 2022 and December 31, 2021, respectively, that is reflected in the Balance Sheet under other current liabilities for pension payments expected to be made over the next twelve months.

The following reflects the impact of the recording of funding status adjustments on the Balance Sheets of CH Energy Group and Central Hudson (In Thousands):

	December 31, 2022(1)(2)	December 31, 2021(1)(2)
Accrued pension costs prior to funding status adjustment	$ (9,559)	$ (26,068)
Funding status adjustment required	67,328	94,796
Prefunded Pension Costs	$ 57,769	$ 68,728
Offset to Funding Status Adjustment - Regulatory Liability - Pension Plan	$ (67,109)	$ (94,773)
Offset to Funding Status Adjustment - Accumulated OCI, Net of Tax of ($61) and ($6), respectively	$ (158)	$ (17)

(1) Includes approximately $0.2 million at December 31, 2022 and December 31, 2021 of accrued pension liability recorded at CH Energy Group as a result of the resignation in 2014 of a CH Energy Group officer with a change in control agreement.

(2) Includes approximately $1.6 million and $1.5 million at December 31, 2022 and December 31, 2021, respectively, that is reflected in the Balance Sheet under other current liabilities for pension payments expected to be made over the next twelve months.

Decisions to fund Central Hudson's Retirement Plan are based on several factors including, but not limited to, the funded status, corporate resources, projected investment returns, actual investment returns, inflation, regulatory considerations, interest rate assumptions, and the requirements of the Pension Protection Act of 2006 ("PPA"). Based on the funding requirements of the PPA, Central Hudson plans to make contributions that maintain the target funded percentage at 80% or higher. Actual contributions could vary significantly based upon a range of factors that Central Hudson considers in its funding decisions.

In accordance with the terms of the Trust agreement for the SERP, following the acquisition of CH Energy Group, Inc. by Fortis on June 27, 2013, Central Hudson is required to maintain a funding level for the SERP at 110% of the present value of the accrued benefits payable under the Plan on an annual basis.

Contributions to the Central Hudson Retirement and SERP Plans are as follows (In Thousands):

	Year Ended December 31,		
	2022	2021	2020
Retirement Plan	$ -	$ -	$ -
SERP	$ -	$ 8,115	$ 6,998

Retirement Plan Discount Rate

The valuation of the current and prior year PBO was determined using discount rates of 5.21% and 2.76% for December 31, 2022 and 2021, respectively, as determined from the Mercer Pension Discount Yield Curve reflecting projected pension cash flows. A 1.0% increase in the discount rate would decrease the projection of the pension PBO by approximately $54.0 million. Central Hudson accounts for pension activity in accordance with PSC-prescribed provisions, which among other things, requires a ten-year amortization of actuarial gains and losses.

The 2018 and 2021 Rate Orders include rate allowances for pension and OPEB expense which approximate the recent cost of providing these benefits. Authorization remains in effect for the deferral of any differences between rate allowances and actual costs under the 1993 PSC Policy to counteract the volatility of these costs.

Retirement Plan Expected Long-Term Rates of Return

The expected long-term rate of return on the Retirement Plan assets utilized in the calculation of the net periodic benefit cost, net of investment expense for December 31, 2022 and 2021 is 4.73% and 4.60%, respectively. In determining the expected long-term rate of return on plan assets, Central Hudson considered forward-looking estimated returns evaluated in light of current economic conditions and based on internally consistent economic models. The expected long-term rate of return is a weighted average based on each plan's investment mix and the forward-looking estimated returns for each investment class. Central Hudson monitors actual performance against target asset allocations and adjusts actual allocations and targets in accordance with the Retirement Plan strategy. A 1.0% decrease in the expected long-term rate of return would have increased the 2022 net periodic benefit cost by approximately $8.6 million.

Retirement Plan Policy and Strategy

Central Hudson's Retirement Plan investment policy seeks to reduce the plan's funded status volatility while targeting a rate of growth equivalent to that of the liability within reasonable risk tolerance levels. In addition to traditional risk and return measures, the policy reflects liability-based considerations, including the Retirement Plan's funded status, contribution requirements, and financial statement items.

Due to market fluctuations, Retirement Plan assets require rebalancing from time to time to maintain the asset allocation within target ranges.

Asset allocation targets in effect as of December 31, 2022, as well as actual asset allocations as of December 31, 2022 and December 31, 2021 expressed as a percentage of the market value of Retirement Plan assets, are summarized in the table below:

Asset Class	Minimum	Target Average	Maximum	December 31, 2022	December 31, 2021
Equity Securities	45%	50%	55%	52.0%	53.2%
Debt Securities	45%	50%	55%	45.3%	45.3%
Other[1]	0%	0%	10%	2.7%	1.5%

[1] Consists of temporary cash investments, as well as receivables for investments sold and interest and payables for investments purchased, which have not settled as of that date.

Management uses outside consultants and outside investment managers to aid in the determination of the Retirement Plan's asset allocation and to provide the management of actual plan assets, respectively.

Retirement Plan Investment Valuation

The Retirement Plan assets consist primarily of investment funds which are valued using Net Asset Value, which is not considered fair value. For those assets that are valued under the current fair value framework, the inputs or methodology used are not necessarily an indication of the risk associated with investing in those securities. See Note 16 – "Accounting for Derivative Instruments and Hedging Activities" for further discussion regarding the definition and levels of fair value hierarchy established by accounting guidance.

Below is a listing of the major categories of plan assets held as of December 31, 2022, and 2021, that are reported at net asset value or fair value, as indicated (Dollars in Thousands):

Investment Type	Value at 12/31/22	% of Total	Value at 12/31/21	% of Total
At Net Asset Value:				
Investment funds - equities	$ 341,011	52.0%	$ 466,054	53.2%
Investment funds - fixed income	99,281	15.1	135,040	15.4
At Fair Value:				
Level 2:				
Cash equivalents	15,680	2.4	11,203	1.3
Investment funds - fixed income	197,603	30.2	261,887	29.9
Other investments	2,058	0.3	1,875	0.2
	$ 655,633	100.0%	$ 876,059	100.0%

Other Post-Retirement Benefits

Central Hudson also provides certain health care and life insurance benefits for certain retired employees through its post-retirement benefit plans. Substantially all of Central Hudson's unionized employees and managerial, professional and supervisory employees ("non-union") hired prior to January 1, 2008, may become eligible for these benefits if they reach retirement age while employed by Central Hudson. Central Hudson amended its OPEB programs for existing non-union and certain retired employees effective January 1, 2008, which eliminated post-retirement benefits for non-union employees hired on or after January 1, 2008. OPEB plans were also amended to eliminate post-retirement benefits for union employees hired on or after May 1, 2008. Benefits for retirees and active employees are provided through insurance companies whose premiums are based on the benefits paid during the year.

The significant assumptions used to account for these benefits are the discount rate, expected long-term rate of return on plan assets, and health care cost trend rate. Central Hudson currently selects the discount rate using the Mercer Pension Discount Yield Curve reflecting projected cash flows. The expected long-term rates of return and the investment policy and strategy for these plan assets are similar to those used for pension benefits previously discussed in this Note. The estimates of health care cost trend rates are based on a review of actual recent trends and projected future trends.

Central Hudson fully recovers its net periodic post-retirement benefit costs in accordance with the 1993 PSC Policy. Under these guidelines, the difference between the amounts of post-retirement benefits recoverable in rates and the amounts of post-retirement benefits determined by an actuarial consultant in accordance with current accounting guidance related to OPEB is deferred as either a regulatory asset or a regulatory liability, as appropriate.

Central Hudson's prefunded asset for OPEB was $31.5 million and $30.5 million at December 31, 2022 and 2021, respectively. The increase in the over-funded status of approximately $1.0 million resulted from a decrease in plan liabilities of approximately $39.0 million, partially offset by a decrease in plan assets of $38.0 million. The decrease in plan liabilities was primarily driven by an increase in the discount rate. The decrease in plan assets was primarily driven by investment losses.

The cumulative amount of net periodic benefit cost in excess of employer contributions at December 31, 2022 and December 31, 2021 was $9.6 million and $0.6 million, respectively. The difference between these amounts and the over-funded asset balance, totaling $21.7 million at December 31, 2022 and $31.1 million at December 31, 2021, will be recognized as a credit in Central Hudson's future expense and has been recorded as a regulatory liability in accordance with the 1993 PSC Policy.

Contribution levels to the OPEB Plans are determined by various factors including the discount rate, expected return on plan assets, medical claims assumptions used, mortality assumptions used, benefit changes, corporate resources, and regulatory considerations.

Contributions to the Central Hudson OPEB Plans were as follows (In Thousands):

	Year Ended December 31,		
	2022	2021	2020
OPEB Plans	$ 528	$ 812	$ 1,081

OPEB Healthcare Cost Trend Rate

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A 1.0% change in assumed health care cost trend rates would have the following effects (In Thousands):

	One Percentage Point	
	Increase	Decrease
Effect on total of service and interest cost components for 2022	$ 784	$ (621)
Effect on year-end 2022 post-retirement benefit obligation	$ 9,044	$ (7,587)

OPEB Discount Rate

The PBO for Central Hudson's obligation for OPEB costs was determined using a discount rate of 5.21% and 2.74% for December 31, 2022 and 2021, respectively. This rate was determined using the

Mercer Pension Discount Yield Curve reflecting projected cash flows. A 1.0% increase in the discount rate for 2022 would have decreased the projection of the OPEB obligation by approximately $10.7 million.

OPEB Expected Long-Term Rates of Return

The expected long-term rate of return on OPEB assets utilized in the calculation of the net periodic benefit cost, net of investment expense for December 21, 2022 and 2021 is 5.14% and 5.01%, respectively. In determining the expected long-term rate of return on plan assets, Central Hudson considered forward-looking estimated returns for each asset class evaluated in light of current economic conditions. The expected long-term rate of return is a weighted average based on each plan's investment mix and the forward-looking estimated returns for each investment class. A 1.0% decrease in the expected long-term rate of return would have increased the 2022 net periodic benefit cost by $1.8 million. Central Hudson monitors actual performance against target asset allocations and adjusts actual allocations and targets, as deemed appropriate, in accordance with the OPEB plan's strategy.

OPEB Policy and Strategy

Central Hudson currently funds its union OPEB obligations through a voluntary employee's beneficiary association ("VEBA") and funds its management OPEB liabilities through a 401(h) plan. The VEBA and 401(h) plan are both a form of trust fund. Central Hudson's VEBA investment policy seeks to achieve a rate of return for the VEBA over the long term that contributes to meeting the VEBA's current and future obligations, including interest and benefit payment obligations. The policy also seeks to earn long-term returns from capital appreciation and current income that at least keep pace with inflation over the long term. Central Hudson's 401(h) plan is invested with the previously mentioned Retirement Plan's investments. However, there are no assurances that the OPEB plan's return objectives will be achieved.

The asset allocation strategy employed in the VEBA reflects Central Hudson's return objectives and what management believes is an acceptable level of short-term volatility in the market value of the VEBA's assets in exchange for potentially higher long-term returns. The mix of assets are broadly diversified by asset class and investment styles within asset classes, based on the following asset allocation targets, expressed as a percentage of the market value of the VEBA's assets, summarized in the table below:

Asset Class	Minimum	Target Average	Maximum	December 31, 2022	December 31, 2021
Equity Securities	55%	65%	75%	66.9%	68.7%
Debt Securities	25%	35%	45%	32.5%	30.9%
Other	- %	- %	- %	0.6%	0.4%

Due to market value fluctuations, the OPEB plan's assets require periodic rebalancing from time to time to maintain the asset allocation within target ranges.

Management uses outside consultants and outside investment managers to aid in the determination of the OPEB plan's asset allocation and to provide the management of actual plan assets, respectively.

OPEB Investment Valuation

The OPEB plan's assets consist primarily of investment funds that are valued using Net Asset Value, which is not considered fair value. For those assets that are valued under the current fair value framework, the inputs or methodology used are not necessarily an indication of the risk associated with investing in those securities. See Note 16 – "Accounting for Derivative and Hedging Activities" for further discussion regarding the definition and levels of fair value hierarchy established by guidance.

Below is a listing of the major categories of plan assets held as of December 31, 2022 and 2021, that are reported at net asset value or fair value, as indicated (Dollars in Thousands):

401(h) Plan Assets

Investment Type	Market Value at 12/31/22	% of Total	Market Value at 12/31/21	% of Total
At Net Asset Value:				
Investment funds - equities	$ 13,308	52.0%	$ 18,429	53.2%
Investment funds - fixed income	3,875	15.1	5,340	15.4
At Fair Value:				
Level 2:				
Cash equivalents	605	2.4	439	1.3
Investment funds - fixed income	7,712	30.2	10,356	29.9
Other investments	87	0.3	78	0.2
	$ 25,587	100.0%	$ 34,642	100.0%

Union VEBA Plan Assets

Investment Type	Market Value at 12/31/22	% of Total	Market Value at 12/31/21	% of Total
At Fair Value:				
Level 1:				
Cash equivalents	$ 723	0.6 %	$ 628	0.4 %
Investment funds - equities	77,686	66.9	99,598	68.7
Investment funds - fixed income	37,671	32.5	44,849	30.9
	$ 116,080	100.0 %	$ 145,075	100.0 %

Detail of the change in Central Hudson's Pension and OPEB benefit obligations, fair value of plan assets, and funded status as of and for the periods ended December 31, 2022 and 2021 are as follows (In Thousands):

	Pension Benefits(1)		Other Post Retirement Benefits	
	2022	2021	2022	2021
Change in Benefit Obligation:				
Benefit Obligation at beginning of year	$ 807,331	$ 854,983	$ 149,237	$ 157,141
Service cost	12,938	15,053	1,588	1,875
Interest cost	22,033	19,849	3,989	3,568
Participant contributions	-	-	1,506	1,332
Plan amendments	-	-	896	-
Benefits paid	(37,808)	(36,012)	(8,620)	(7,609)
Actuarial gain	(206,630)	(46,542)	(38,391)	(7,070)
Benefit Obligation at end of year	$ 597,864	$ 807,331	$ 110,205	$ 149,237
Change in Value of Plan Assets:				
Fair Value of Plan Assets at beginning of year	$ 876,059	$ 828,170	$ 179,717	$ 163,638
Actual return on plan assets	(182,163)	84,281	(31,363)	21,848
Employer contributions	1,488	1,476	528	812
Participant contributions	-	-	1,506	1,332
Benefits paid	(37,808)	(36,012)	(8,620)	(7,609)
Other	(1,943)	(1,856)	(101)	(304)
Fair Value of Plan Assets at end of year	$ 655,633	$ 876,059	$ 141,667	$ 179,717
Funded Status at end of year	$ 57,769	$ 68,728	$ 31,462	$ 30,480

(1) The plan assets as presented in this chart do not include approximately $39.7 million and $40.1 million of SERP trust assets at December 31, 2022 and 2021.

The following table summarizes the employee future benefit assets and liabilities and their classifications on the Consolidated Balance Sheets and Statements of Comprehensive Income at December 31 (In Thousands):

	Pension Benefits[1]		Other Post Retirement Benefits	
	2022	2021	2022	2021
Amounts Recognized on Balance Sheet:				
Noncurrent assets	$ 59,365	$ 70,222	$ 31,462	$ 30,480
Current liabilities	(1,596)	(1,494)	-	-
Funded Status at end of year	$ 57,769	$ 68,728	$ 31,462	$ 30,480
Regulatory asset:				
Net actuarial gain	$ (68,452)	$ (96,441)	$ (21,224)	$ (29,264)
Prior service costs (credit)	$ 1,124	$ 1,645	$ (518)	$ (1,841)
Other comprehensive income:				
Net actuarial gain, net of tax	$ (158)	$ (18)	$ (6)	$ (2)
Prior service costs, net of tax	$ (2)	$ 1	$ -	$ -

(1) The funded status in this chart does not reflect approximately $39.7 million and $40.1 million of SERP trust assets at December 31, 2022 and 2021.

Central Hudson's net periodic benefit costs for its Pension and OPEB plans for the periods ended December 31, 2022 and 2021 are as follows (In Thousands):

	Pension Benefits		Other Post Retirement Benefits	
	2022	2021	2022	2021
Components of Net Periodic (Benefit) Cost:				
Service cost	$ 12,938	$ 15,053	$ 1,588	$ 1,875
Interest cost	22,033	19,849	3,989	3,568
Expected return on plan assets	(39,412)	(36,168)	(8,970)	(7,944)
Amortization of prior service cost (credit)	521	527	(427)	(456)
Amortization of recognized actuarial net (gain)/loss	(11,102)	2,532	(5,726)	(2,601)
Net Periodic (Benefit) Cost	$ (15,022)	$ 1,793	$ (9,546)	$ (5,558)

The following table provides the components recognized in net periodic benefit cost and as regulatory assets, which otherwise would have been recognized in comprehensive income, as well as the weighted average assumptions used in the periods (Dollars In Thousands):

	Pension Benefits[1]		Other Post Retirement Benefits	
	2022	2021	2022	2021
Other Changes in Plan Assets and Benefit Obligation Recognized in Regulatory Assets:				
Net loss (gain)	$ 16,888	$ (92,801)	$ 2,313	$ (20,431)
Amortization of actuarial net gain (loss)	11,102	(2,532)	5,726	2,601
Plan amendments [2]	-	-	896	-
Amortization of prior service (cost) credit	(521)	(527)	427	456
Total recognized in regulatory asset	$ 27,469	$ (95,860)	$ 9,362	$ (17,374)
Total Recognized in Net Periodic Cost (Benefit) and Regulatory Asset	$ 12,447	$ (94,067)	$ (184)	$ (22,932)
Weighted-average assumptions used to determine benefit obligations:				
Discount rate	5.21%	2.76%	5.21%	2.74%
Rate of compensation increase (average)	3.90%	3.90%	3.90%	3.90%
Measurement date	12/31/22	12/31/21	12/31/22	12/31/21
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31:				
Discount rate	2.76%	2.34%	2.74%	2.32%
Expected long-term rate of return on plan assets	4.73%	4.60%	5.14%	5.01%
Rate of compensation increase (average)	3.90%	3.90%	3.90%	3.90%

Assumed health care cost trend rates at December 31:				
Health care cost trend rate assumed for next year	N/A	N/A	6.84%	6.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.00%	4.00%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2047	2046
Accumulated Benefit Obligation	$ 570,905	$ 756,806	N/A	N/A

(1) The fair value of plan assets presented in this chart does not include approximately $39.7 million and $40.1 million of SERP trust assets at December 31, 2022 and 2021.

(2) The plan amendment represents the new post-retirement Health Reimbursement Account negotiated for certain union employees as part of the Union Agreement and also extended to certain management employees.

Estimated net loss of $10.5 million and prior service cost of $0.5 million for the defined benefit pension plans will be amortized from regulatory asset and OCI respectively, into net periodic benefit cost over the next fiscal year. Estimated net gain of $5.0 million and prior service credit of $0.4 million for the other defined benefit post-retirement plans will be amortized from regulatory asset and OCI respectively, into net periodic benefit cost over the next fiscal year. The amount of transitional obligation to be amortized from regulatory asset and OCI is immaterial.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service as appropriate, are expected to be paid (In Thousands):

Year	Pension Benefits - Gross	Other Benefits - Gross	Other Benefits - Net[(1)]
2023	$ 39,580	$ 8,203	$ 7,663
2024	39,944	8,527	7,976
2025	40,619	8,684	8,116
2026	41,505	8,984	8,405
2027	42,102	9,037	8,437
Next five years	211,673	42,763	39,498

(1) Estimated benefit payments reduced by estimated gross amount of Medicare Act of 2003 subsidy receipts expected.

401(k) Retirement Plan

Central Hudson sponsors a 401(k) plan for its employees. The 401(k) plan provides for employee tax-deferred salary deductions for participating employees and employer matches. The matching benefit varies by employee group. Central Hudson’s matching contributions for the years ended December 31, 2022, 2021, and 2020 were $6.0 million, $5.8 million, and $5.6 million, respectively. Central Hudson also provides an additional contribution of 4% to the 401(k) plan of annualized base salary for eligible employees who do not qualify for Central Hudson’s Retirement Income Plan. The additional non-discretionary contribution was approximately $3.2 million, $2.8 million, and $2.7 million for 2022, 2021, and 2020, respectively.

NOTE 13 – Equity-Based Compensation

Share Unit Plan Units

In January 2022, officers of Central Hudson were granted 12,781 Units under the 2022 Fortis Restricted Share Unit Plan (“2022 RSUP”), representing a portion of the officers’ long-term incentives. The 2022 Restricted Units granted are time-based and vest at the end of the three-year period without regard to performance. Each 2022 RSUP Unit granted has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash, unless a participant does not satisfy their share ownership requirements or chooses to settle in shares. The settlement in shares by a participant will result in the modification from a liability award to an equity award and an election to settle in shares and cannot be made later than 30 days prior to the awards vesting. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of that 2022 RSUP Unit grant. Each 2022 RSUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In January 2022, officers of Central Hudson were also granted 25,562 Units under the Central Hudson 2022 Share Unit Plan (“2022 SUP”), representing a portion of the officers’ long-term incentives. The 2022 SUP Units granted are performance based and vest at the end of the three-year performance period upon achievement of specified cumulative performance goals. Each 2022 SUP Unit granted has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of that 2022 SUP Unit grant. Each 2022 SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In January 2021, officers of Central Hudson were granted Units under the 2021 Fortis Restricted Share Unit Plan (“2021 RSUP”), representing a portion of the officers’ long-term incentives. The 2021 Restricted Units granted were time-based and vest at the end of the three-year period without regard to performance. Each 2021 RSUP Unit granted has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash, unless a participant does not satisfy their share ownership requirements or chooses to settle in shares. The settlement in shares by a participant will result in the modification from a liability award to an equity award and an election to settle in shares cannot be made later than 30 days prior to the awards vesting. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of that 2021 RSUP Unit grant. Each 2021 RSUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In January 2021, officers of Central Hudson were granted Units under the Central Hudson 2021 Share Unit Plan (“2021 SUP”), representing a portion of the officers’ long-term incentives. The 2021 SUP Units granted were performance based and vest at the end of the three-year performance period upon achievement of specified cumulative performance goals. Each 2021 SUP Unit granted has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of that 2021 SUP Unit grant. Each 2021 SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In 2020, officers of CH Energy Group and Central Hudson were granted Units under the 2020 Fortis Restricted Share Unit Plan (“2020 RSUP”), representing a portion of the officers’ long-term incentives. The 2020 Restricted Units granted are time-based and vest at the end of the three-year period without regard to performance. Each 2020 RSUP Unit granted has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash, unless a participant does not satisfy their share ownership requirements or chooses to settle in shares. The settlement in shares by a participant will result in the modification from a liability award to an equity award and an election to settle in shares cannot be made later than 30 days prior to the awards vesting. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of the 2020 RSUP Unit grant. Each 2020 RSUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In prior periods, CH Energy Group granted Units to an officer of CH Energy Group under Performance Share Unit Plans, the (“2020 PSUP”) in 2020 and the (“2019 PSUP”) in 2019, (collectively “PSUP”). The PSUP Units granted under these plans are primarily performance based and vest upon achievement of specified performance goals over the applicable three-year performance period. The 2019 PSUP also included the grant of time-based awards that vest at the end of the three-year period without regard to performance. Each PSUP Unit has an underlying value equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash. The foreign exchange rate utilized for cash payout in the US dollar equivalent corresponds to the exchange rate on the business day prior to the date of the PSUP Unit grant. Each PSUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

Officers of Central Hudson were granted Units under the Central Hudson 2020 (“2020 SUP”), and the 2019 (“2019 SUP”) Share Unit Plans, collectively the (“SUP plans”), representing a portion of the officers’ long-term incentives. The 2020 SUP Units granted are performance based and vest at the end of the three-year performance period upon achievement of specified cumulative performance goals. Two-thirds of the SUP Units granted under the 2019 SUP are performance based and vest at the end of the respective three-year performance period upon achievement of specified cumulative performance goals. The remaining SUP Units that were granted under the 2019 SUP, are time-based and vest at the end of the respective three-year period without regard to performance. For all grants issued under the SUP plans, each SUP Unit is equivalent to the value of one common share of Fortis and, if earned and vested, is paid in cash. The foreign exchange rate utilized for cash payout in the US dollar equivalent for each plan corresponds to the exchange rate on the business day prior to the date of that SUP Unit grant. Each SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

Awards granted under the 2019 PSUP and 2019 SUP Plans vested and were paid out during the first quarter of 2022.

CH Energy Group:			Grant Date	Time Based		Performance Based	
	Grant Date		Fair Value	Granted	Outstanding[5]	Granted	Outstanding[5]
2020 RSUP[2][3]	January 1, 2020	$	41.55	7,257	-	-	-
2020 PSUP[2]	January 1, 2020	$	41.55	-	-	21,770	24,317
2019 PSUP[1]	January 1, 2019	$	33.10	8,838	-	26,514	-

Central Hudson:			Grant Date	Time Based		Performance Based	
	Grant Date		Fair Value	Granted	Outstanding[5]	Granted	Outstanding[5]
2022 RSUP[4]	January 1, 2022	$	48.18	12,781	12,384	-	-
2022 SUP	January 1, 2022	$	48.18	-	-	25,562	26,526
2021 RSUP[4]	January 1, 2021	$	41.12	14,249	14,374	-	-
2021 SUP	January 1, 2021	$	41.12	-	-	28,497	30,704
2020 RSUP[2][4]	January 1, 2020	$	41.55	12,655	13,164	-	-
2020 SUP[2]	January 1, 2020	$	41.55	-	-	25,311	28,272
2019 SUP[1]	January 1, 2019	$	33.10	15,691	-	31,383	-

[1]In the first quarter of 2022, 46,656 units under the 2019 SUP and 39,431 units under the 2019 PSUP vested and were paid out at $44.78 per unit for a total of approximately $5.3 million.

[2]During 2020, the grant date fair value share price was corrected from the previously disclosed Canadian dollar share price of CAD$53.97 to the US dollar share price. There was no financial statement impact resulting from the change to the disclosure.

[3]In the third quarter of 2022, per the 2020 RSUP agreement, time-based units were paid out related to an Officer retirement at 7,811 shares at $61.08 per unit.

[4]In the fourth quarter of 2022, as a result of a separation of employment, 962 units of 2020 RSUP, 968 units of 2021 RSUP and 870 units of 2022 RSUP were forfeited.

[5]Includes notional dividends accrued as of December 31, 2022.

Compensation Expense

The following table summarizes compensation expense for share unit plan units as follows (In Thousands):

	Year Ended December 31,		
	2022	2021	2020
CH Energy Group	$ 44	$ 2,617	$ 2,434
Central Hudson	$ 44	$ 2,618	$ 2,435

The liabilities associated with the RSUP, SUP, and PSUP plans are recorded at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the respective liabilities is based on the Fortis common share 5-day volume weighted average trading price at the end of each reporting period and the expected payout based on management's best estimate in accordance with the defined metrics of each grant.

Under the RSUP, SUP, and PSUP agreements (the "Plans"), the amount of any outstanding awards payable to an employee who retires during the term of the grant and who has 15 years of service and provides at least six months prior notice of retirement under the terms of the Plans (ninety days prior notice with respect to the 2022 Plans), is determined as if the employee continued to be an employee through the end of the performance period. In accordance with ASU 2014-12, in this situation, compensation expense for that individual is recognized over the requisite service period, instead of the performance period. In all periods presented, additional expense was recognized in accordance with ASU 2014-12 for Central Hudson officers who are retirement eligible under terms of the Plans in which they have attained the required retirement age and met the required 15 years of service. Fluctuations in compensation expense in the comparative periods can result from changes in the Fortis Inc. common stock share price and the projected performance payout percentages.

Employee Share Purchase Plan

Effective May 17, 2017, the Company adopted the Fortis Amended and Restated 2012 Employee Share Purchase Plan ("ESPP"). Fortis authorized 600,000 of its common shares to be offered under the ESPP. The ESPP allows eligible employees of Fortis and adopting subsidiaries to contribute during any investment period an amount not less than 1% and not more than 10% of their eligible compensation to purchase Fortis' common shares. Under the ESPP, employees are entitled to fund contributions through interest free loans from the Company. At December 31, 2022 and 2021, employee loans due to the Company related to the ESPP were approximately $0.3 million and $0.2 million, respectively.

The ESPP provides that the Company will contribute as additional salary, an amount equal to 10% of an employee's contribution up to a maximum contribution of 1% of eligible compensation. The Company will also contribute an amount equal to 10% of all dividends payable by Fortis on all common stock allocated to an employee's ESPP account. Common shares are purchased under the ESPP concurrent with the quarterly dividend payment dates of March 1, June 1, September 1, and December 1.

NOTE 14 – Commitments and Contingencies

Electricity Purchase Commitments

Central Hudson meets its capacity and electricity obligations through contracts with capacity and energy providers, purchases from the NYISO energy and capacity markets, and its own generating capacity.

Energy Credit Purchase Obligations

In August 2016, the PSC issued Order 15-E-0302 adopting a Clean Energy Standard ("CES") that outlined a LSE obligation for Renewable Energy Credits ("RECs") and Zero-Emissions Credit ("ZECs") requirements to meet New York State clean energy goals. This Order charged NYSERDA to work with the DPS Staff to develop an Implementation Plan for each CES Program for approval by the PSC. Tier 1 and Tier 2 Competitive RECs and Tier 3 ZECs are "pay-as-you-go" based on Central Hudson's monthly full-service customer load volume as defined by NYISO billing data and a load modifier adjustment factor. Presently, there are four Tiers comprising five different LSE obligations:

Tier 1 RECs: The 2016 CES Order, for which Central Hudson's obligations began in January 2017, directed NYSERDA to perform annual Divergence Tests to monitor CES program performance. LSEs, which include Central Hudson, have been required to obtain Tier 1 RECs in amounts determined by the PSC. Beginning in January 2021, NYSERDA introduced Indexed Tier 1 RECs to replace the fixed REC pricing model. Tier 1 REC pricing is set through quarterly competitive auctions and a weighted average of vintage fixed and new indexed RECs. An Alternative Compliance Payment ("ACP") is set in advance of each compliance year. In March 2022, the PSC issued a Modifying Order that revised the Tier 1 REC obligations through calendar year 2024. LSEs may satisfy their Tier 1 REC obligation by purchasing Tier 1 RECs acquired through central procurement from NYSERDA, direct purchase of tradable Tier 1 RECs on the secondary market, through Value Stack offset or by making ACPs. Central Hudson has satisfied Tier 1 REC obligations from Value Stack offset through December 2022. At December 31, 2022, the forward Tier 1 obligations for Central Hudson full-service customers is estimated to be approximately $5.2 million through December 31, 2024.

Tier 2 Maintenance RECs: Obligations are assessed to an electric transmission territory for any Renewable Portfolio Standard program generator with proven financial hardship. Presently, Central Hudson has no Tier 2 Maintenance REC obligations in its service territory.

Tier 2 Competitive RECs: In October 2020, the PSC issued a Modifying Order that set requirements for Tier 2 Competitive RECs through calendar year 2025 with a New York State-wide cap of $200 million. Central Hudson's full-service customer load-ratio share of the cap is $4 million. Tier 2 REC pricing is administratively set by NYSERDA based on Tier 2 auction results. No awards were made by NYSERDA in the last two Requests For Proposals ("RFPs") and as of November 2022, calendar year 2023, will be the last year of the current Tier 2 Competitive program. NYSERDA is soliciting industry comments for ideas on how to modify the program. At this time, Central Hudson's Tier 2 Competitive REC obligations have been materially reduced from $4 million to less than $0.05 million. Central Hudson's full-service customer obligation will be immaterial through December 31, 2023.

Tier 3 ZECs: Obligations began in April 2017 and the CES contemplated six two-year tranches for a total of 12 years of obligations through March 2029. ZEC requirements are based on an administratively determined, annually defined, price to support the financial health of three nuclear plants in upstate New York. At December 31, 2022, Central Hudson's estimated Tier 3 ZEC obligation through March 31, 2023 is estimated to be approximately $2.9 million.

Tier 4 RECs: Future obligations for Tier 4 RECs are outlined in the October 2021 CES Modifying Order. These RECs will be tied to deliverability requirements into New York City NYISO Zone J. Central Hudson has no Tier 4 REC obligations defined at this time.

The estimated cost projections listed above are recoverable from full-service customers through electric cost adjustment mechanism and, therefore, do not impact earnings.

Commitments

The following is a summary of commitments for CH Energy Group and its affiliates as of December 31, 2022 (In Thousands):

	Projected Payments Due By Period						
	Year Ending 2023	Year Ending 2024	Year Ending 2025	Year Ending 2026	Year Ending 2027	Thereafter	Total
Recorded Contractual Obligations:							
Operating leases	$ 564	525	$ 469	$ 422	$ 1,708	$ -	$ 3,688
Repayments of long-term debt	2,100	32,245	22,400	50,000	50,000	969,401	1,126,146
Current installments of credit facilities	105,000	-	-	-	-	-	105,000
Stock-based compensation obligations	2,782	1,048	844	-	-	-	4,674
Unrecorded Contractual Obligations:							
Purchased electric contracts (1)	14,378	3,247	143	143	143	143	18,197
REC purchase agreements (1)	5,476	2,704	-	-	-	-	8,180
Purchased natural gas contracts (1)	38,385	15,453	8,322	6,780	3,611	10,335	82,886
Interest obligations on long-term debt	46,561	45,126	44,243	43,822	41,378	582,687	803,817
Total	$ 215,246	$ 100,348	$ 76,421	$ 101,167	$ 96,840	$ 1,562,566	$ 2,152,588

(1) Purchased electric, purchased natural gas costs, and REC purchase agreements for Central Hudson are fully recovered via their respective regulatory cost adjustment mechanisms.

The following is a summary of commitments for Central Hudson as of December 31, 2022 (In Thousands):

	Projected Payments Due By Period						
	Year Ending 2023	Year Ending 2024	Year Ending 2025	Year Ending 2026	Year Ending 2027	Thereafter	Total
Recorded Contractual Obligations:							
Operating leases	$ 564	$ 525	$ 469	$ 422	$ 1,708	$ -	$ 3,688
Repayments of long-term debt	-	30,000	20,000	50,000	50,000	969,400	1,119,400
Current installments of credit facilities	105,000	-	-	-	-	-	105,000
Stock-based compensation obligations	1,658	1,048	844	-	-	-	3,550
Unrecorded Contractual Obligations:							
Purchased electric contracts (1)	14,378	3,247	143	143	143	143	18,197
REC purchase agreements (1)	5,476	2,704	-	-	-	-	8,180
Purchased natural gas contracts (1)	38,385	15,453	8,322	6,780	3,611	10,335	82,886
Interest obligations on long-term debt	46,137	44,848	44,120	43,822	41,378	582,687	802,992
Total	$ 211,598	$ 97,825	$ 73,898	$ 101,167	$ 96,840	$ 1,562,565	$ 2,143,893

(1) Purchased electric, purchased natural gas costs, and REC purchase agreements for Central Hudson are fully recovered via their respective regulatory cost adjustment mechanisms.

Other Commitments

Capital Expenditures

Central Hudson is a regulated utility and, as such, is obligated to provide service to customers within its service territory. Central Hudson's capital expenditures are largely driven by the need to ensure the continued and enhanced reliability and safety of the electric and natural gas systems for the long-term benefit of customers.

Pension Benefit and OPEB Funding Contributions

Central Hudson is subject to certain contractual benefit payment obligations. Decisions about how to fund the Retirement and OPEB Plans to meet these obligations are made annually and are primarily affected by the discount rate used to determine benefit obligations, current asset values, corporate resources, and the projection of Retirement and OPEB Plan assets. Based on the funding requirements of the Pension Protection Act of 2006, Central Hudson plans to make contributions that maintain the target funded percentage for the Retirement Plan at 80% or higher. Actual contributions could vary significantly based upon economic growth, projected investment returns, inflation and interest rate assumptions. Actual funded status could vary significantly based on asset returns and changes in the discount rate used to estimate the present value of future obligations. In January 2023, Central Hudson made an immaterial contribution to the 401(h) Plan to fund the OPEB plan, in accordance with Central Hudson's OPEB policy and strategy.

Supplemental Executive Retirement Plan

As a result of the acquisition of CH Energy Group, Inc. by Fortis on June 27, 2013, and in accordance with the terms of the Trust agreement for the SERP, Central Hudson is required to maintain a funding level at 110% of the present value of the accrued benefits payable under the Plan on an annual basis. Annual contributions to the SERP could vary based on investment returns, discount rates, and participant demographics. At December 31, 2022, the SERP was fully funded for 2022, in accordance with the requirements of the Trust agreement.

Parental Guarantee

CHET was established to be an investor in Transco, which was created to develop, own and operate electric transmission projects in New York State. On July 16, 2020, CH Energy Group's parental guarantee to Transco was adjusted from $182.0 million to $73.7 million. The Transco Board of Directors approved the reduction based on CHET's maximum commitment associated with the AC Project, the only project remaining under Transco's original FERC application and the initial guarantee. As of December 31, 2022, the amount of the outstanding parental guarantee is $54.5 million. CH Energy Group is currently not aware of any existing condition that would require any payments under this guarantee.

Contingencies

Environmental Matters

Central Hudson

- Site Investigation and Remediation Program

Central Hudson has been notified by the New York State Department of Environmental Conservation ("DEC") that it believes Central Hudson or its predecessors, at one time, owned and/or operated manufactured gas plants ("MGP") to serve their customers' heating and lighting needs, at seven sites in Central Hudson's franchise territory. The DEC has further requested that Central Hudson investigate and, if necessary, remediate these sites. In addition, Central Hudson is also performing environmental SIR at two non-MGP sites within its service territory, Little Britain Road, and Eltings Corners.

Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated at a point in time. At December 31, 2022, Central Hudson has accrued $73.9 million with respect to all SIR activities, including operation, maintenance, and monitoring costs ("OM&M"), of which $3.7 million is anticipated to be spent in the next twelve months.

SIR can be divided into various stages of completion based on the milestones of activities completed and reports reviewed. The types of costs accrued during the various stages include:

1. *Investigation* – Begins with preliminary investigations and is completed upon filing and approval by DEC of a Remedial Investigation ("RI") Report. Central Hudson accrues for estimated investigation costs.

2. *Remedial Alternatives Analysis ("RAA")* – Engineering analysis of alternatives for remediation based on the RI is compiled into a RAA Report. Management accrues for an estimate of remediation costs developed and quantified in the RAA based on DEC approved methods, as well as an estimate of post-remediation OM&M. These amounts represent a significant portion of the total costs to remediate and are subject to change based on further investigations, final remedial design and associated engineering estimates, regulatory comments and requests, remedial design changes/negotiations, and changed or unforeseen conditions during the remediation or additional requirements following the remediation. Prior to the completion of the RAA, management cannot reasonably estimate what cost will be incurred for remediation or post-remediation activities.

3. *Remedial Design* - Upon approval of the RAA and final decision of remediation approach based on alternatives presented, a Remedial Design ("RD") or Remedial Action Work Plan is developed and filed with the DEC for approval.

4. *Remediation* – Completion of the work plan as defined in the approved RD. Upon completion, final reports are filed with the DEC for approval and may include a Construction Completion Report, Final Engineering Report, or other reports required by the DEC based on the work performed.

5. *Post-Remediation Monitoring* – Entails the OM&M as directed by the DEC based on the approved final report of remediation. The activities are typically defined in a Site Management Plan, which is approved by the DEC. The extent of activities during this phase may increase or decrease based on the results of ongoing monitoring being performed and future potential usage of the property.

6. *No Action Required* – No further investigation or remedial action is currently required. No further costs are expected, and no amounts are accrued related to this site.

These stages, the costs accrued and the sites currently in each stage include (Dollars in Millions):

Stage	**Sites**	**Total Accrued Cost at December 31, 2022**	**Estimated spend in the next twelve months**
Investigation	Little Britain Road	$ 2.0	$ 0.1
Remedial alternatives analysis		-	-
Remedial design		-	-
Remediation	North Water Street	67.6	3.5
Post-remediation monitoring	Newburgh Areas A, B & C, Laurel Street, Catskill, Kingston, and Eltings Corners	4.3	0.1
No action required	Beacon and Bayeaux Street	-	-
Total		$ 73.9	$ 3.7

There were no significant updates during the twelve months ended December 31, 2022 or changes in the nature and amounts of Central Hudson's contingencies related to environmental matters, except as noted below.

- **Remediation in Progress - Site – North Water Street**
  - In the first quarter of 2020, Central Hudson revised its estimate and recorded the low end of the range of projected costs for remediation activities associated with this site based on an assessment of a high-solids hydraulic dredging remedial alternative including predictive cost modeling for a pilot test and full-scale remediation.
  - In September 2020, the New York State Department of Environmental Conservation ("NYSDEC") approved the Hydraulic Dredging Pilot Test ("HDPT") Work Plan and Water Supply Protection and Contingency Plan. Preliminary site monitoring and mobilization activities commenced in October 2020 and pilot test activities, including demobilization, were completed in January 2021.
  - The goals of the pilot study were successfully achieved. Hydraulic dredging was completed in three areas with different degrees of impacted sediment (no impact, medium impact and high impact). A draft hydraulic dredge pilot test evaluation summary report was prepared, which summarized the data compiled related to:
    - production rates associated with the hydraulic dredge equipment in each area, including the impacts of the protective shroud attached for additional protection;
    - impacts of sheening events that occurred, the ability to contain them, and the related work stoppages during the pilot;
    - impact of prescribed protective measures regarding the placement of daily clean cover and backfill on the riverbed; and
    - debris encountered in the river and the related mechanical removal.
  - The report concluded that the use of hydraulic dredging was technically feasible. However, there were several factors (as noted above) that impacted the previously estimated production rates able to be achieved during the pilot. When extrapolated to full-scale remediation, the cumulative effect of these impacts on the production rates observed during the HDPT significantly increased the total estimated time to complete the dredging and backfilling remediation and, as a result of this increased time frame, also equated to a significant increase in the projected cost.
  - Based on the increase in the projected time frame and cost, it was concluded by the project's Engineer of Record ("EOR") that full-scale hydraulic dredging is not practical to pursue as the sole remedial approach. Following review of the evaluation summary report, the NYSDEC concurred that this timeframe was not practical and agreed with the conclusion of the report. At this point, the NYSDEC has communicated that removal of source material is still the best long-term remedy for the site and, as such, is directing Central Hudson to examine other methods, including a mix of alternative approaches taking into consideration the extent of removal that may be feasible.
  - A scope of work for limited upland remedial activities was submitted to and approved by the NYSDEC in May 2021. The activities were completed in June 2021.
  - During 2021, Central Hudson worked with the EOR to evaluate remedial alternative approaches, including some that still fit within the framework of the NYSDEC approved Work Plan and achieved the established regulatory clean-up objectives within a reasonable time period, as well as other approaches that considered capping or monitoring-only activities. A Focused Remedial Alternatives Analysis ("FRAA") report presenting the evaluation of alternative approaches was submitted to the NYSDEC in November 2021. A preliminary follow up discussion was held with the NYSDEC in December 2021.
  - An Air Bubble Curtain ("ABC") lab pilot test work plan was provided to the NYSDEC for informational purposes on January 11, 2022. Central Hudson has kept the NYSDEC informed as the study progressed and will provide a summary report upon conclusion. The field portion of the ABC bench scale pilot test activities were completed on December 10, 2022. Modeling and reporting will continue into the first quarter of 2023. Depending on the results of the laboratory testing and modeling, in-river testing may be conducted beginning in 2023.

- On April 8, 2022, Central Hudson received a response from the NYSDEC with regard to the November 2021 FRAA. Central Hudson sent a response to the comments on May 24, 2022. Overall, the comment letter indicated that the tests of alternate containment methods (i.e., ABC pilot test) should be completed prior to consideration of the alternatives presented in the FRAA report and, therefore, the NYSDEC rejected the report at this time. The comment letter also requested additional information be provided and additional concerns be addressed as the process continues. There is no change in the current course of action and focus, which is the completion of the ABC pilot test and communication with the parties on the results of the effectiveness and protectiveness. The comments and additional information requests in the comment letter will be contemplated in a more detailed Remedial Design and/or work plan that will be developed once concurrence is received on an acceptable alternative approach. As such, management believes this comment letter does not provide evidence of any adjustment required to the low end of the range currently accrued, or the total range of potential costs disclosed at this time, and it does not impact management's method of estimating the range and liability recorded as of December 31, 2022. Furthermore, management believes that the alternatives included in the FRAA continue to be the best potential remedial options going forward and, as such, continues to accrue for the cost at the low end of the range.
- The total accrual for remediation as of December 31, 2022, for this site of $67.6 million reflects management's estimate of the low end of a predictive cost estimate range of potential alternatives, including an adjustment for inflation of $3.2 million plus additional costs associated with the ABC, continued work of the EOR on the development of design and analysis of the FRAA based on future discussions with other parties, and other associated fees. The FRAA included potential alternatives for remediation with costs estimated as high as $95 million. The accrual will be updated as the alternative remedial approaches are discussed, and a path forward is agreed upon by all involved parties.
- The estimated spending as of December 31, 2022, for the next 12 months of approximately $3.5 million is primarily based on anticipated efforts to complete analysis, modeling, and reporting of the results of the laboratory bench scale testing of an ABC, and dependent upon results, conduct in-river testing, and continue discussions regarding alternative remedial approaches following completion of the ABC test(s).

Future remediation activities, including OM&M and related costs may vary significantly from the assumptions used in Central Hudson's current cost estimates and these costs could have a material adverse effect (the extent of which cannot be reasonably determined) on the financial condition, results of operations, and cash flows of CH Energy Group and Central Hudson if Central Hudson were unable to recover all or a substantial portion of these costs via collection in rates from customers and/or through insurance.

Central Hudson expects to recover its remediation costs from its customers. The current components of this recovery include:

- As part of the 2021 Rate Order, Central Hudson maintained previously granted deferral authority and future recovery for the differences between actual Environmental SIR costs (both MGP and non-MGP) and the associated rate allowances, with carrying charges, to be accrued on the deferred balances at the authorized pre-tax rate of return.
- The 2021 Rate Order includes cash recovery of approximately $24.2 million during the three-year rate plan period ending June 30, 2024, with $11.8 million recovered through December 31, 2022. The 2018 Rate Order included cash recovery of $25.7 million through the rate plan period ended June 30, 2021, all of which had been fully recovered.
- The total spending related to site investigation and remediation for the years ended December 31, 2022 and 2021 was approximately $1.2 million and $3.3 million, respectively.

- The regulatory asset balance as of December 31, 2022 and December 31, 2021 was $71.4 million and $76.0 million, respectively, which represents the cumulative difference between amounts spent or currently accrued as a liability and the amounts recovered to date through rates or insurance recoveries.

Central Hudson has put its insurers on notice and intends to seek reimbursement from its insurers for its costs. Certain of these insurers have denied coverage. There were no insurance recoveries during the years ended December 31, 2022 and 2021. We do not expect insurance recoveries to offset a meaningful portion of total costs.

Litigation

Asbestos Litigation

Central Hudson is involved in various asbestos lawsuits.

As of December 31, 2022, of the 3,387 asbestos cases brought against Central Hudson, 1,164 remain pending. Of the cases no longer pending against Central Hudson, 2,058 have been dismissed or discontinued without payment by Central Hudson and Central Hudson has settled 164 cases. Central Hudson is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including Central Hudson’s experience in settling asbestos cases and in obtaining dismissals of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material adverse effect on the financial position, results of operations or cash flows of either CH Energy Group or Central Hudson.

Other Litigation

CH Energy Group and Central Hudson are involved in various other legal and administrative proceedings incidental to their businesses, which are in various stages. While these matters collectively could involve substantial amounts, based on the facts currently known, it is the opinion of management that their ultimate resolution will not have a material adverse effect on either CH Energy Group’s or Central Hudson’s financial positions, results of operations or cash flows. CH Energy Group and Central Hudson expense legal costs as incurred.

NOTE 15 – Segments and Related Information

CH Energy Group's reportable operating segments are the regulated electric utility business and regulated natural gas utility business of Central Hudson. Other activities of CH Energy Group, which do not constitute a business segment, include CHEC’s former investment in a limited partnership, CHET’s investment in Transco (a regulated entity), CHGT which has no current activity, and the holding company’s activities, which consist primarily of financing its subsidiaries, and are reported under the heading “Other Businesses and Investments.”

General corporate expenses and Central Hudson’s property common to both electric and natural gas segments have been allocated in accordance with practices established for regulatory purposes. The common allocation per the terms of the 2021 Rate Order and the 2018 Rate Order is 80% for electric and 20% for natural gas.

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2022				
	Segments		Other		
	Central Hudson		Businesses		
		Natural	and		
	Electric	Gas	Investments	Eliminations	Total
Revenues from external customers	$ 797,612	$ 220,744	$ -	$ -	$ 1,018,356
Intersegment revenues	56	1,159	-	(1,215)	-
Total operating revenues	797,668	221,903	-	(1,215)	1,018,356
Energy supply costs	323,558	80,234	-	(1,215)	402,577
Operating expenses	354,747	84,586	315	-	439,648
Depreciation and amortization	60,624	19,392	-	-	80,016
Operating income (loss)	58,739	37,691	(315)	-	96,115
Other income, net	33,803	8,737	2,559	-	45,099
Interest charges	27,945	12,402	554	-	40,901
Income before income taxes	64,597	34,026	1,690	-	100,313
Income tax expense	12,084	8,447	649	-	21,180
Net Income Attributable to CH Energy Group	$ 52,513	$ 25,579	$ 1,041	$ -	$ 79,133
Segment Assets at December 31, 2022	$ 2,399,549	$ 907,893	$ 27,371	$ (779)	$ 3,334,034
Capital Expenditures	$ 158,897	$ 65,945	$ -	$ -	$ 224,842

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2021				
	Segments		Other		
	Central Hudson		Businesses		
		Natural	and		
	Electric	Gas	Investments	Eliminations	Total
Revenues from external customers	$ 623,823	$ 172,425	$ -	$ -	$ 796,248
Intersegment revenues	59	243	-	(302)	-
Total operating revenues	623,882	172,668	-	(302)	796,248
Energy supply costs	178,795	48,504	-	(302)	226,997
Operating expenses	320,246	76,256	218	-	396,720
Depreciation and amortization	55,234	17,481	-	-	72,715
Operating income (loss)	69,607	30,427	(218)	-	99,816
Other income, net	20,344	5,273	1,937	-	27,554
Interest charges	25,384	10,536	681	-	36,601
Income before income taxes	64,567	25,164	1,038	-	90,769
Income tax expense	10,700	5,408	708	-	16,816
Net Income Attributable to CH Energy Group	$ 53,867	$ 19,756	$ 330	$ -	$ 73,953
Segment Assets at December 31, 2021	$ 2,169,728	$ 805,355	$ 22,458	$ (882)	$ 2,996,659
Capital Expenditures	$ 156,918	$ 74,664	$ -	$ -	$ 231,582

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2020				
	Segments		Other Businesses and Investments	Eliminations	Total
	Central Hudson				
	Electric	Natural Gas			
Revenues from external customers	$ 552,002	$ 159,893	$ -	$ -	$ 711,895
Intersegment revenues	52	209	-	(261)	-
Total operating revenues	552,054	160,102	-	(261)	711,895
Energy supply costs	136,182	37,430	-	(261)	173,351
Operating expenses	302,534	72,132	241	-	374,907
Depreciation and amortization	50,847	16,016	-	-	66,863
Operating income (loss)	62,491	34,524	(241)	-	96,774
Other income, net	17,000	5,018	1,120	-	23,138
Interest charges	25,099	9,648	800	-	35,547
Income before income taxes	54,392	29,894	79	-	84,365
Income tax expense	9,058	6,087	117	-	15,262
Net Income (Loss) Attributable to CH Energy Group	$ 45,334	$ 23,807	$ (38)	$ -	$ 69,103
Segment Assets at December 31, 2020	$ 1,886,780	$ 737,757	$ 20,805	$ (1,218)	$ 2,644,124
Capital Expenditures	$ 170,931	$ 81,926	$ -	$ -	$ 252,857

NOTE 16 – Accounting for Derivative Instruments and Hedging Activities

Purpose of Derivatives

Central Hudson enters into derivative contracts in conjunction with the Company's energy risk management program to hedge certain risk exposure related to its business operations. The derivative contracts are typically either exchange-traded or over the counter ("OTC") instruments. The primary risks the Company seeks to manage by using derivative instruments are interest rate risk, commodity price risk, and adverse or unexpected weather conditions. Central Hudson uses derivative contracts to reduce the impact of volatility in the prices of natural gas and electricity and to hedge exposure to volatility in interest rates for its variable rate long-term debt. Derivative transactions are not used for speculative purposes. Central Hudson's derivative activities consist of the following:

- Interest rate caps are used to minimize interest rate risks and to improve the matching of assets and liabilities. An interest rate cap is an interest rate option agreement in which payments are made by the seller of the option when the reference rate exceeds the specified strike rate (or the set rate at which the option contract can be exercised). The purpose of these agreements is to reduce exposure to rising interest rates while still having the ability to take advantage of falling interest rates by putting a "cap" on the interest rate Central Hudson pays on debt for which such caps are purchased. See Note 11 - "Capitalization – Long-Term Debt" for further details regarding Central Hudson's interest rate cap agreements.

- Natural gas futures are used to mitigate commodity price volatility for natural gas purchases. A natural gas futures contract is a standardized contract to buy or sell a specified commodity (natural gas) of standardized quantity at a certain date in the future, at a market determined price (the futures price). Central Hudson's reason for purchasing these contracts is to moderate price fluctuations for natural gas and the impact of volatility in the commodity markets on its customers.

- Electricity swaps are used to mitigate commodity price volatility for electricity purchases for Central Hudson's full-service customers. A swap contract or a contract for differences is the exchange of two payment streams between two counterparties where the cash flows are dependent on the price of the underlying commodity. In an effort to moderate commodity price volatility, Central Hudson enters into contracts to pay a fixed price and receive a market price for a defined commodity and volume. These contracts are aligned with Central Hudson's actual commodity purchases at market price, resulting in a net fixed price payment.

- Weather derivative contracts are used to hedge the effect of significant variances in weather conditions from normal patterns on purchased electricity and natural gas costs, and on the related revenues. Heating Degree Days ("HDD") are used to measure winter temperature risk where an HDD index is calculated by subtracting the average of the daily high and low temperatures from 65 degrees fahrenheit, representing the point where space heating is typically switched on. In recent years these daily HDD values are accumulated over the seasonal period of December 1st to March 31st where a strike price is triggered to protect the Company from price volatility when the HDD value is 45 degrees below the stated 65 degree starting point. Prior to 2021, premiums were paid for these weather-related instruments and they were amortized based on the pattern of normal purchases of electricity or natural gas over the term of the contract and any payouts earned were recorded as a reduction of the cost. In 2021, instead of paying an upfront premium for weather derivative contracts, Central Hudson added an additional feature to pay the financial institution, if and when, weather is warmer than normal during the winter seasonal period. While customers are protected by price volatility at 45 degrees below 65 degrees fahrenheit, there is now a trigger to pay the financial institution when the HDD daily calculation does not fall 20.5 degrees below its 65 degree starting point. These values are accumulated daily and any payouts earned will continue to be netted with costs on a monthly basis over the term of the contract.

Energy Contracts Subject to Regulatory Deferral

Central Hudson has been authorized to fully recover certain risk management costs through its natural gas and electricity cost adjustment mechanisms. Risk management costs are defined by the PSC as costs associated with transactions that are intended to reduce price volatility or reduce overall costs to customers. These costs include transaction costs and gains and losses associated with risk management instruments. The related gains and losses associated with Central Hudson's derivatives are included as part of Central Hudson's commodity cost and/or price-reconciled in its natural gas and electricity cost adjustment charge mechanisms and are not designated as hedges.

The percentage of Central Hudson's electric and natural gas requirements covered with fixed price forward purchases at December 31, 2022 are as follows:

Central Hudson	% of Requirement Hedged [1]
Electric Derivative Contracts:	0.6 million MWh
January 2023 – August 2023	33.9%
Natural Gas Derivative Contracts:	0.3 million Dth
January 2023 – March 2023	6.9%

[1] Projected coverage as of December 31, 2022.

In 2022, OTC derivative contracts covered approximately 30.8% of Central Hudson's total electricity supply requirements as compared to 29.6% in 2021.

Cash Flow Hedges

Central Hudson has been authorized to fully recover the interest costs associated with its $33.7 million Series B NYSERDA Bonds and its $30.0 million of variable rate debt, which includes costs and gains or losses associated with its interest rate cap contracts.

Derivative Risks

The basic types of risks associated with derivatives are market risk (that the value of the derivative will be adversely impacted by changes in the market, primarily the change in commodity prices and interest rates) and credit risk (that the counterparty will not perform according to the terms of the contract). The market risk of the derivatives generally offset the market risk associated with the hedged commodity.

The majority of Central Hudson's derivative instruments contain provisions that require Central Hudson to maintain specified issuer credit ratings and financial strength ratings. Should Central Hudson's ratings fall below these specified levels, it would be in violation of the provisions and the derivatives' counterparties could terminate the contracts and request immediate payment.

To help limit the credit exposure of derivatives, Central Hudson enters into master netting agreements with counterparties whereby contracts in a gain position can be offset against contracts in a loss position. Of the 26 total agreements held by Central Hudson, 11 agreements contain credit risk contingent features. As of December 31, 2022, five open contracts with credit risk contingent features were in a liability position. The aggregate fair value of the open derivative contracts that contain contingent features and the amount that would be required to settle these instruments on December 31, 2022, if the contingent features were triggered, are described below.

Contingent Contracts
(Dollars In Thousands)

	As of December 31, 2022		
Triggering Event	# of Contracts in a Liability Position Containing the Triggering Feature	Gross Fair Value of Contract	Cost to Settle if Contingent Feature is Triggered (net of collateral)
Central Hudson:			
Credit Rating Downgrade	5	$ (13,545)	$ (13,545)
Total Central Hudson	5	$ (13,545)	$ (13,545)

Derivative Contracts

CH Energy Group and Central Hudson have elected gross presentation for their derivative contracts under master netting agreements and collateral positions. On December 31, 2022 and December 31, 2021, Central Hudson did not have collateral posted against the fair value amount of derivatives.

The net presentation for CH Energy Group's and Central Hudson's derivative assets and liabilities are as follows (In Thousands):

				Gross Amounts Not Offset in the Statement of Financial Position		
Description	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2022[1]						
Derivative Contracts:						
Central Hudson - electric	$ 315	$ -	$ 315	$ 315	$ -	$ -
Total CH Energy Group and Central Hudson Assets	$ 315	$ -	$ 315	$ 315	$ -	$ -
As of December 31, 2021[1]						

Derivative Contracts:						
Central Hudson - electric	$ 1,604	$ -	$ 1,604	$ 380	$ -	$ 1,224
Central Hudson - natural gas	164	-	164	-	-	164
Total CH Energy Group and Central Hudson Assets	$ 1,768	$ -	$ 1,768	$ 380	$ -	$ 1,388

(1) Interest rate cap agreements are not shown in the above chart. As of December 31, 2022 and 2021, the fair value was $0.

				Gross Amounts Not Offset in the Statement of Financial Position		
Description	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2022(1)						
Derivative Contracts:						
Central Hudson - electric	$ 13,389	$ -	$ 13,389	$ 315	$ -	$ 13,074
Central Hudson - natural gas	645	-	645	-	-	645
Total CH Energy Group and Central Hudson Liabilities	$ 14,034	$ -	$ 14,034	$ 315	$ -	$ 13,719
As of December 31, 2021(1)						
Derivative Contracts:						
Central Hudson - electric	$ 7,563	$ -	$ 7,563	$ 380	$ -	$ 7,183
Central Hudson - natural gas	-	-	-	-	-	-
Total CH Energy Group and Central Hudson Liabilities	$ 7,563	$ -	$ 7,563	$ 380	$ -	$ 7,183

(1) Interest rate cap agreements are not shown in the above chart. As of December 31, 2022 and 2021, the fair value was $0.

Gross Fair Value of Derivative Instruments

Current accounting guidance related to fair value measurements establishes a fair value hierarchy to prioritize the inputs used in valuation techniques based on observable and unobservable data, but not the valuation techniques themselves. Observable inputs are inputs that reflect the assumptions market participants would use in pricing the asset or liability. Unobservable inputs are inputs that reflect the reporting entity’s own assumptions about the assumptions market participants would use in pricing an asset or a liability. Classification of inputs is determined based on the lowest level input that is significant to the overall valuation. The fair value hierarchy prioritizes the inputs to valuation techniques into the three categories described below:

Level 1 Inputs: Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs: Directly or indirectly observable (market-based) information. This includes quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 Inputs: Unobservable inputs for the asset or liability for which there is either no market data, or for which asset and liability values are not correlated with market value.

Derivative contracts are measured at fair value on a recurring basis. As of December 31, 2022 and 2021, CH Energy Group's and Central Hudson's derivative assets and liabilities by category and hierarchy level are as follows (In Thousands):

Asset or Liability Category	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2022(1)				
Assets:				

Derivative Contracts:				
Central Hudson - electric	$ 315	$ -	$ 315	$ -
Central Hudson - natural gas	-	-	-	-
Total CH Energy Group and Central Hudson Assets	$ 315	$ -	$ 315	$ -
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ 13,389	$ -	$ 13,389	$ -
Central Hudson - natural gas	645	645	-	-
Total CH Energy Group and Central Hudson Liabilities	$ 14,034	$ 645	$ 13,389	$ -
As of December 31, 2021[1]				
Assets:				
Derivative Contracts:				
Central Hudson - electric	$ 1,604	$ -	$ 1,604	$ -
Central Hudson - natural gas	164	164	-	-
Total CH Energy Group and Central Hudson Assets	$ 1,768	$ 164	$ 1,604	$ -
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ 7,563	$ -	$ 7,563	$ -
Central Hudson - natural gas	-	-	-	-
Total CH Energy Group and Central Hudson Liabilities	$ 7,563	$ -	$ 7,563	$ -

(1) Interest rate cap agreements are not shown in the above chart. These are classified as Level 2 in the fair value hierarchy using SIFMA Municipal Swap Curves and 3-month US Dollar Libor rate forward curves. As of December 31, 2022 and 2021, the fair value was $0.

The Effect of Derivative Instruments on the Statements of Income

Realized gains and losses on Central Hudson's derivative instruments are returned to or recovered from customers through PSC authorized deferral accounting mechanisms, with no material impact on cash flows, results of operations, or liquidity. Realized gains and losses on Central Hudson's energy derivative instruments are reported as part of purchased natural gas, purchased electricity, and fuel used in electric generation in CH Energy Group's and Central Hudson's Statements of Income as the corresponding amounts are either recovered from or returned to customers through fuel cost adjustment mechanisms in revenues. Additionally, unrealized gains and losses on Central Hudson's derivative contracts have no impact on earnings since the energy contracts are subject to regulatory deferral.

For the years ended December 31, 2022, 2021 and 2020, neither CH Energy Group nor Central Hudson had derivatives designated as hedging instruments. The following table summarizes the effects of CH Energy Group's and Central Hudson's derivatives on the Statements of Income (In Thousands):

	Amount of Gain(Loss) Recognized as Increase/(Decrease) in the Statements of Income			
	Year Ended December 31,			
	2022	2021	2020	Location of Gain (Loss)
Central Hudson:				
Electricity swap contracts	$ (3,934)	$ (1,687)	$ (14,379)	Deferred purchased electric costs[1]
Natural gas swap contracts	430	404	(866)	Deferred purchased natural gas costs[1]
Total CH Energy Group and Central Hudson	$ (3,504)	$ (1,283)	$ (15,245)	

(1) Realized gains and losses on Central Hudson's derivative instruments are returned to or recovered from customers through PSC authorized deferral accounting mechanisms with no net impact on results of operations.

Other Hedging Activities

Central Hudson – Electric

In October 2022, Central Hudson entered into an HDD costless collar weather option for the period December 1, 2022 through March 31, 2023, to hedge the effect of significant variances in weather conditions on electricity costs. The aggregate limit on the contract is $5 million. No premium was paid for the HDD costless collar weather option and there was no associated net payout at the end of December 2022. Central Hudson's expense recorded to purchased electric cost was not material through December 31, 2022.

In 2021, Central Hudson entered into an HDD costless collar weather option for the period December 1, 2021 through March 31, 2022, with an aggregate limit of $5 million. There was no associated net payout at the end of the contract. Central Hudson recorded $0.3 million of expense incurred as an increase to purchase electric cost. In 2020, Central Hudson entered into premium based weather options for the periods of December 1, 2020 through March 31, 2021. The aggregate limit per contract was $5 million. Premiums paid were amortized to purchased electricity over the term of the agreements. The payout earned of $0.6 million was recorded as a reduction to purchased electricity in the Statements of Income in the periods earned.

Central Hudson – Natural Gas

In October 2022, Central Hudson entered into an HDD costless collar weather option for the period December 1, 2022 through March 31, 2023, to hedge the effect of significant variances in weather conditions on natural gas costs. The aggregate limit on the contract was $5 million. No premium was paid for the HDD costless collar weather option and there was no net associated payout at the end of December 2022. Central Hudson's expense recorded to natural gas cost was not material through December 31, 2022.

In 2021, Central Hudson entered into an HDD costless collar weather option for the period December 1, 2021 through March 31, 2022, with an aggregate limit of $5 million. There was no associated net payout at the end of the contract. Central Hudson recorded $0.3 million of expense incurred as an increase to natural gas cost. In 2020, Central Hudson entered into premium based weather options for the periods of December 1, 2020 through March 31, 2021. The aggregate limit per contract was $5 million. Premiums paid were amortized to purchased natural gas over the term of the agreements. The payout earned of $0.1 million was recorded as a reduction to purchased natural gas in the Statements of Income in the periods earned.

NOTE 17 – Other Fair Value Measurements

Other Assets Recorded at Fair Value

In addition to the derivatives reported at fair value discussed in Note 16 – "Accounting for Derivative Instruments and Hedging Activities," CH Energy Group and Central Hudson report certain other assets at fair value on the Balance Sheets. The following table summarizes the amounts reported at fair value related to these assets (In Thousands):

	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2022:				
Other investments	$ 20,645	$ 20,645	$ -	$ -
As of December 31, 2021:				
Other investments	$ 21,624	$ 21,624	$ -	$ -

As of December 31, 2022 and 2021, a portion of the trust assets for the funding of the SERP and Deferred Compensation Plan were invested in mutual funds and money market accounts, which are measured at fair value on a recurring basis. These investments are valued at quoted market prices in active markets and, as such, are Level 1 investments as defined in the fair value hierarchy. These amounts are included in “Other investments” within the Deferred Charges and Other Assets section of the CH Energy Group’s and Central Hudson’s Balance Sheets.

The remaining amount reported in “Other investments” represents trust assets for the funding of the SERP and Deferred Compensation Plan held in trust-owned life insurance policies, which are recorded at cash surrender value. As of December 31, 2022 and 2021, the total cash surrender value of trust-owned life insurance held by these trusts was approximately $33.5 million and $35.3 million, respectively. The change in the cash surrender value is reported in “Other – net” income in the CH Energy Group’s and Central Hudson’s Income Statements.

Other Fair Value Disclosure

Financial instruments are recorded at carrying value in the financial statements, however, the fair value of these instruments is disclosed below in accordance with current accounting guidance related to financial instruments.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Cash Equivalents: Carrying amount.

Short-Term Borrowings: Carrying amount.

Due to the short-term nature of these borrowings, the carrying value is equivalent to the current fair market value.

Long-term Debt: Quoted market prices for the same or similar issues (Level 2).

Valuations were obtained for each issue using the observed Treasury market in conjunction with secondary market trading levels and recent new issuances of comparable companies.
The following tables summarize the long-term debt maturing or to be redeemed during the next five years and thereafter, as well as the estimated fair value of both CH Energy Group and Central Hudson’s long-term debt, including the current maturities (Dollars in Thousands):

CH Energy Group

	Fixed Rate		Variable Rate		Total Debt Outstanding	
Expected Maturity Date	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate
As of December 31, 2022:						
2023	$ 2,100	7.00%	$ -	-%		
2024	2,245	7.00%	30,000	5.76%		
2025	22,400	3.43%	-	-%		
2026	50,000	3.73%	-	-%		
2027	50,000	2.60%	-	-%		
Thereafter	935,701	4.14%	33,700	6.65%		
Total	$ 1,062,446	4.05%	$ 63,700	6.23%	$ 1,126,146	4.17%

Fair Value	$ 896,255		$ 63,700		$ 959,955	
As of December 31, 2021:						
2022	$ 25,364	3.70%	$ -	-%		
2023	2,100	6.95%	-	-%		
2024	2,245	6.95%	30,000	1.22%		
2025	22,401	3.43%	-	-%		
2026	50,000	3.73%	-	-%		
Thereafter	765,700	4.14%	33,700	0.14%		
Total	$ 867,810	4.10%	$ 63,700	0.65%	$ 931,510	3.86%
Fair Value	$ 1,012,654		$ 63,700		$ 1,076,354	

Central Hudson

	Fixed Rate		Variable Rate		Total Debt Outstanding	
Expected Maturity Date	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate
As of December 31, 2022:						
2023	$ -	-%	$ -	-%		
2024	-	-%	30,000	5.76%		
2025	20,000	3.00%	-	-%		
2026	50,000	3.73%	-	-%		
2027	50,000	2.60%	-	-%		
Thereafter	935,700	4.14%	33,700	6.65%		
Total	$ 1,055,700	4.03%	$ 63,700	6.23%	$ 1,119,400	4.15%
Fair Value	$ 889,524		$ 63,700		$ 953,224	
As of December 31, 2021:						
2022	$ 23,400	3.42%	$ -	-%		
2023	-	-%	-	-%		
2024	-	-%	30,000	1.22%		
2025	20,000	3.00%	-	-%		
2026	50,000	3.73%	-	-%		
Thereafter	765,700	4.14%	33,700	0.14%		
Total	$ 859,100	4.07%	$ 63,700	0.65%	$ 922,800	3.83%
Fair Value	$ 1,003,268		$ 63,700		$ 1,066,968	

NOTE 18 – Related Party Transactions

Thompson Hine LLP serves as outside counsel to CH Energy Group and Central Hudson. One partner in that firm serves as each corporation’s General Counsel and Corporate Secretary. LaBella Associates D.P.C. (formerly The Chazen Companies) performs engineering services for Central Hudson, and a principal in the firm serves as a director of Central Hudson.

The following are fees paid by CH Energy Group and Central Hudson to Thompson Hine LLP and LaBella Associates D.P.C., respectively, as follows (In Thousands):

	Year Ended December 31,		
	2022	2021	2020
CH Energy Group (Thompson Hine LLP)	$ 2,474	$ 2,031	$ 2,264
Central Hudson (Thompson Hine LLP)	$ 2,445	$ 1,993	$ 2,233
Central Hudson (LaBella Associates D.P.C.)	$ 546	$ 786	$ 710

CH Energy Group and Central Hudson may provide general and administrative services ("services") to and receive services from each other, Fortis, and other subsidiaries of Fortis. The costs of these services are reimbursed by the beneficiary company through accounts receivable and accounts payable, as necessary. CH Energy Group and Central Hudson may also incur charges from Fortis or each other for the recovery of general corporate expenses incurred by one another, Fortis, or other affiliates. In addition, CH Energy Group and Central Hudson may also incur charges from Fortis for federal income taxes under their tax sharing agreement. These transactions are in the normal course of business and are recorded at the United States dollar amounts.

Furthermore, Central Hudson performs work and incurs expenses on behalf of Transco, a company in which CHET has a 6.1% equity interest. Central Hudson bills Transco for such work and expenses in accordance with established policies, which are reported under "Other Affiliates" in the chart below.

Related party transactions included in accounts receivable and accounts payable for CH Energy Group and Central Hudson are as follows (In Thousands):

	December 31, 2022	December 31, 2021
CH Energy Group[1]	Fortis	Fortis
Accounts Receivable	$ 441	$ 1,390
Accounts Payable	$ 624	$ -

	December 31, 2022			December 31, 2021		
Central Hudson[1][2]	CHEG	Fortis	Other Affiliates	CHEG	Fortis	Other Affiliates
Accounts Receivable	$ 10	$ 183	$ 195	$ 36	$ 7	$ -
Accounts Payable	$ 1,365	$ -	$ -	$ 823	$ -	$ 1

(1) Fortis amounts include Fortis and all Fortis subsidiaries.

(2) Other Affiliates amounts include CHEC, CHET, and Transco.

Related party transactions in operating expenses for CH Energy Group and Central Hudson are as follows (In Thousands):

	December 31, 2022		December 31, 2021		December 31, 2020	
	CHEG	Fortis[1]	CHEG	Fortis[1]	CHEG	Fortis[1]
CH Energy Group	$ -	$ 4,886	$ -	$ 4,055	$ -	$ 3,692
Central Hudson	$ 5,409	$ -	$ 4,442	$ -	$ 4,172	$ -

(1)Fortis amounts reported above include Fortis and all Fortis subsidiaries.

NOTE 19 – Subsequent Events

An evaluation of subsequent events was completed through February 9, 2023, the date these Consolidated Financial Statements were available to be issued, to determine whether circumstances warranted recognition and disclosure of events or transactions in the Consolidated Financial Statements as of December 31, 2022.

On January 20, 2023, Fitch affirmed the (A-) rating of Central Hudson's senior unsecured debt and changed its rating outlook from stable to negative. Fitch indicated Central Hudson's rating reflects the low-risk nature of its regulated electric and gas utility operations. However, the negative outlook reflects Fitch's concerns regarding the credit supportiveness of the PSC, with particular regard to the outcome of the Company’s next rate case to support future credit metrics consistent with Central Hudson’s current rating.

On January 30, 2023, the Transco Board of Managers gave notice to CHET that it will be required to make a $3.4 million capital contribution to Transco during the first quarter of 2023 to fund capital expenditures related to the Transco AC Project.

MANAGEMENT'S DISCUSSION and ANALYSIS of FINANCIAL CONDITION and RESULTS of OPERATIONS
For the Year Ended December 31, 2022

This Management Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the 2022 Financial Statements and the notes thereto.

Overview

CH Energy Group is the holding company parent corporation of four principal, wholly owned subsidiaries, Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"), Central Hudson Enterprises Corporation, Central Hudson Electric Transmission LLC ("CHET"), and Central Hudson Gas Transmission LLC ("CHGT"). Central Hudson is a regulated electric and natural gas transmission and distribution utility. CH Energy Group formed CHET to hold its 6.1% ownership interest in New York Transco LLC ("Transco"). Transco is a joint venture with affiliates of other investor-owned utilities in New York State, which was created to develop, own, and operate electric transmission projects in New York State. CHGT was formed to hold CH Energy Group's ownership stake in possible gas transmission pipeline opportunities in New York State. All of CH Energy Group's common stock is indirectly owned by Fortis Inc. ("Fortis"), a leader in the North American regulated electric and gas utility industry, with 2022 revenue of CAD$11.0 billion and total assets of CAD$64 billion as of December 31, 2022. Fortis and its subsidiaries' 9,200 employees serve 3.4 million utility customers in five Canadian provinces, nine U.S. states, and three Caribbean countries.

Central Hudson purchases and sells energy in both wholesale and retail markets and distributes electricity and natural gas to customers in retail markets in portions of New York State. Central Hudson is subject to regulation by the New York Public Service Commission ("PSC" or "Commission") and the Federal Energy Regulatory Commission ("FERC").

CH Energy Group Strategy Execution

CH Energy Group's strategy is to:

- Invest primarily in electric and gas transmission and distribution; and
- Maintain a financial profile that supports Central Hudson's objective of a credit rating in the "A" category.

Management continues to focus on investment in Central Hudson's electric and natural gas infrastructure as the core of its strategy. Central Hudson invested approximately $225 million in 2022, and its five-year forecast includes an average of approximately $280 million of capital expenditures per year. The long-term capital program provides for continued strengthening of existing electric and natural gas infrastructure, resiliency and automation of distribution systems, new common facilities, and investments in cybersecurity, and information and distribution system technologies that are expected to allow for greater penetration of distributed energy resources and improve reliability and customer satisfaction.

As part of CH Energy Group's overall strategy to invest in electric transmission and distribution, CHET made an investment in Transco. In April 2019, National Grid and Transco were awarded the Segment B portion of one of their proposals related to the Alternating Current Transmission Order with NYISO for a transmission project that will improve the flow of power from upstate renewable resources to meet downstate demand and enhance the reliability and resilience of the grid ("AC Project"). Transco is authorized to earn a return on equity invested in the project (up to 53% of the project cost) of 9.65%, with up to an additional 1% available for incentives. The project has an estimated cost of $600 million plus interconnection costs and CHET's equity funding requirement of this cost as a 6.1% owner of Transco is expected to be $19.4 million. At December 31, 2022, CHET's investment in Transco was approximately $23.5 million.

In November 2018, the Transco limited liability company agreement was amended to allow Transco to pursue additional projects that might result from future New York Independent System Operator's ("NYISO") Public Policy Transmission Planning Processes. In response to a Long Island Offshore Wind Export Public Policy Transmission Need Project Solicitation issued by the NYISO on August 12, 2021, Transco, partnering with the New York Power Authority ("NYPA"), submitted to NYISO on October 11, 2021, four separate proposed solutions to upgrade existing transmission facilities on Long Island to accommodate 3,000 megawatts ("MW") of anticipated offshore wind generated electricity, while also proposing three alternative expansion solutions. Three unrelated developers proposed 12 other solutions. NYISO's response to the solicitation proposals, including the Transco-NYPA proposals, is expected to be issued in the first half of 2023. In the event that a Transco-NYPA proposal is accepted by NYISO, CHET would own, and fund, the equity investment associated with Transco's 10% ownership stake in the project.

Central Hudson
Purpose and Strategy Execution

Central Hudson's Purpose Statement is **"Together We Power Endless Possibilities,"** which is supported by the following Core Values:

- *We Never Compromise on **Safety***
- *We Value Our **People***
- *We Put the **Customer** First*
- *We Aim for **Excellence** Every Day*
- *We Put Energy Into Our **Communities***

Central Hudson's strategy is to provide exceptional value to its stakeholders by:

- modernizing and transforming our business through electric and natural gas system investments and process improvements;
- continuously improving our performance while maintaining cost effective, efficient, and secure operations;
- advocating on behalf of customers and other stakeholders; and
- investing in programs and employee development to position the organization for continued success in the future.

Central Hudson has developed a range of strategic objectives that, once achieved, will address the technology and policy changes faced by New York utilities; meet or exceed the increasing expectations of our customers and provide creative solutions in anticipation of evolving customer need in the mid-Hudson Valley; influence the regulatory and political landscape in a manner that provides value to our key stakeholders; and position the Company for continued success with a flexible, diverse, talented, and engaged workforce.

Central Hudson is subject to regulation by the PSC. Central Hudson's earnings are derived predominately from the revenue it generates from delivering energy to approximately 300,000 electric and 80,000 natural gas customers, with earnings growth coming primarily from increases in net utility plant. Central Hudson's delivery rates are designed to recover the cost of providing safe and reliable service while affording the opportunity to earn a fair and reasonable return on its capital.

Central Hudson is committed to continuing the transition to a low carbon and sustainable future for our customers and the communities we serve. Sustainability and strong social responsibility are at the core of Central Hudson's plans and actions and are integrated throughout all facets of the business. Central Hudson appreciates the need to continuously improve and is ,therefore, taking the actions needed to ensure a successful future: fortifying and protecting its delivery systems, embracing new technologies, managing aggressive energy policy goals, and actively supporting evolving customer needs. The Company remains dedicated to the safety, health, and well-being of every employee and contractor, as well as the community and customers we serve.

Central Hudson is actively pursuing a cleaner energy future by supporting New York State's energy policies and goals, while continuing to provide reliable, resilient, and affordable power. At Central Hudson, we continue to make investments in infrastructure, technologies, and programs that cost-effectively reduce carbon emissions by:

- upgrading electric transmission and distribution lines, including support for statewide transmission upgrades to deliver renewable energy sources to areas of high electric demand including the Hudson Valley and metropolitan area, and investments in the regional electric distribution system to facilitate greater levels of locally sited renewable generators;
- pursuing the lowest cost approach to emission reduction by examining current incentives to determine which offer the highest value in lowering emissions;
- integrating natural gas benefits, utilized for fast-start electric generation, to enable intermittent renewable resources and used as a low-carbon alternative to petroleum-derived fuels used in heating and manufacturing to reduce overall carbon emissions;
- expanding energy efficiency programs, the most cost-effective method to reduce emissions; and
- advancing environmentally beneficial electrification, including promoting electric vehicles and heat pumps, to lower emissions from the transportation and building heating sectors.

Central Hudson is taking a leading role in reducing emissions in the mid-Hudson Valley through investments in programs that include beneficial electrification (i.e., expanding the electric vehicle charging infrastructure and increasing heat pump installations), grid modernization and reinforced infrastructure in support of renewables, energy efficiency and energy storage system interconnections. The investments into Central Hudson's operations and reduction of carbon emissions are aligned with and support New York State's Climate Leadership and Community Protection Act ("CLCPA"). The CLCPA has mandated an 85% greenhouse gas ("GHG") emissions reduction from 1990 levels by 2050. In addition, we continue to seek opportunities to update and modernize our operations as we adapt to an evolving clean energy landscape while building towards a more sustainable future. At Central Hudson, these efforts take place in a broader context of a heightened focus on Environment, Social, and Governance ("ESG") factors. We believe that the transparent management of ESG performance and related goals are important for our stakeholders to understand the path we are taking towards our sustainability goals and for Central Hudson to provide assurance around the integrity of the broader operating environment in which those targets are being pursued. Strong ESG performance is expected to yield long-term value through enhanced earnings, reduced costs, improved stakeholder relationships, increased employee satisfaction, and optimization of investment and capital expenditures.

Central Hudson has continued its journey to transform the customer experience. Having navigated the challenges and difficulties of replacing a decades-old Customer Billing System ("CIS") and implementing a new state-of-the-art system, we are looking forward to the benefits that the new system will provide to our customers. We aim to satisfy our customers by being proactive, responsive, dependable, and timely when they need service. We want to reach each customer on a variety of service channels and provide them the level of support they need, including self-service options. We are committed to the reliability that customers expect, even when more frequent severe weather events impact our service territory. We have taken a proactive approach to harden our electric and natural gas systems accordingly and participated in a climate assessment to evaluate the resilience of our business in different potential climate-related futures. At Central Hudson, we value our customers and our employees, and we strive to support a sustainable environment for all.

Human Capital Resources

Central Hudson recognizes the critical importance of its employees and dedicates substantial resources and efforts toward attracting, retaining, and developing individuals who exemplify the values that are the cornerstone of our Company. In our Purpose Statement we make it clear that our people are absolutely essential to our success. As of December 31, 2022, we had 1,130 employees, with approximately 55% covered by collective bargaining ("union") agreements. In addition, we work with many outside firms to obtain additional resources to supplement our internal forces to address fluctuations in certain aspects of the Company's operations, including contact center overflow, storm restoration, capital construction, tree trimming, and other field operations. We strive to maintain good relationships with both our union and suppliers of contracted services.

Safety is of the utmost importance for our employees and is a priority for our Company. We value continuous improvement in everything we do, including safety, and we have devoted additional resources, including external consultation services and collaboration with our union on a grass roots effort to improve our safety performance and culture.

We believe that our compensation and benefit programs are appropriately designed to attract and retain first-class talent. We provide our employees competitive compensation, a comprehensive benefits package, and extensive training and professional development opportunities.

We strive to provide a safe, inclusive and diverse environment for all. We want our employees to know that their individual input and contribution is valued and to feel that they can be their authentic selves at work. We believe that by recognizing and valuing each employee for who they are, we make our shared goals possible. We also place great focus on veteran recruiting. Veterans currently comprise approximately 6% of our current workforce and contribute to the organization as some of our most skilled and productive employees. In addition to our internal commitments to inclusion and diversity, we also have a supplier diversity program that is committed to developing an inclusive supplier base through the selection of businesses owned by minorities, women, and veterans when all other considerations are equal.

Opportunities and Risks

Central Hudson invests significant capital on an annual basis. Central Hudson's investments enhance safety and reliability through solutions, which are intended to improve customer satisfaction and reduce risk. Opportunities to enhance transmission and distribution systems and information systems technologies are evaluated and prioritized based on their expected benefits, projected costs, and estimated risks. On November 18, 2021, the PSC issued an Order Approving Rate Plan in Cases 20-E-0428 and 20-G-0429 ("2021 Rate Order"), which included a request for continued funding of Central Hudson's capital investment program.

The economy in Central Hudson's service territory affects the growth of utility rate base and earnings through a direct relationship to customer affordability, customer additions and peak demand growth, as well as affecting Central Hudson's ability to collect receivables. Management believes the economy in Central Hudson's service territory has reasonable long-term growth prospects, but unexpected prolonged downturns could inhibit its ability to meet long-term business objectives. Central Hudson has an economic development program intended to increase job growth and income in its service territory. Management believes Central Hudson's commitments to providing safe and reliable service, customer satisfaction, operational excellence, and promoting positive customer and regulatory relations are important for supportive regulatory relationships and obtaining full cost recovery and competitive returns on invested capital.

The key risks management sees in achieving its overall strategy are operating risks related to effectively executing its capital program, managing costs and customer bill pressure, maintaining customer satisfaction, navigating the current political and regulatory environment, as well as ensuring adherence to compliance requirements as further discussed below. Central Hudson has policies, procedures, and controls in place which Central Hudson believes allows it to address these risks.

COVID-19

Central Hudson has taken measures to support our customers, employees, and communities impacted by COVID-19 and to support the economic recovery in our service territory. For all of its customers, Central Hudson suspended certain collection activities, including terminating service for non-payment; waived finance charges; and doubled its contribution to its last resort grant program. For small businesses, the Company accelerated certain energy efficiency programs and committed up to $1 million of Economic Development funding through our Back to Business program. Central Hudson has been and continues to be proactively contacting customers regarding past due balances to advise them of certain financial assistance programs available to them and to proactively engage with them in managing these balances with deferred payment arrangements. Central Hudson is also working with local agencies and municipalities to obtain funding for its customers, which has been made available through several federal and state programs.

Central Hudson had increased its reserve for uncollectible accounts during 2021 by $0.8 million based on a quantitative and qualitative assessment of the growing customer past due balances and management's best estimate of forecasted economic conditions related to COVID-19. No further increase to the reserve has been recorded throughout 2022, based on the potential available funding from federal and state programs to assist customers financially impacted by COVID-19 pay off their utility arrears balances.

Additionally, Central Hudson's 2021 Rate Order incorporated reductions from the initial planned rate increase request to mitigate the bill impact on customers. These reductions included delays in certain planned investments and reductions to operations and maintenance ("O&M"), which management believes could be accomplished without impacting safety and reliability. Additionally, in this approved Rate Order, the Company received authorization for the deferral and recovery of significant COVID-19-related costs, net of any savings, including incremental O&M, write-off of uncollectible customer balances, and lost finance charges.

Regulatory/Compliance Risks:

- Compliance/penalty risks: Central Hudson needs to comply with several agencies which include PSC, FERC, North American Electric Reliability Corporation ("NERC"), Department of Environmental Conservation ("DEC"), The Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and NYISO. These entities have the authority to impose penalties on Central Hudson for violations of the Federal Power Act, the Natural Gas Act, or related rules, including reliability and cyber security rules. Environmental agencies could seek penalties for failure to comply with laws, regulations, or permits. Central Hudson may be subject to new laws, regulations, or other requirements or the revision or reinterpretation of such requirements, which could adversely affect the Company.

- Regulatory Environment: PSC rates are generally designed for, but do not guarantee the recovery of, Central Hudson's cost of service, including a return on equity. Central Hudson's ability to meet its financial objectives is largely dependent on approval of the Company's rate proposals and the continuation of supportive ratemaking practices by the PSC. Risks related to these practices include: (1) reduced allowed returns on equity, (2) PSC-allowed revenues that result in less than full recovery of the legitimate costs of providing service, resulting in earned returns below authorized returns, (3) declining PSC support for strong capital structures and credit ratings, (4) New York State energy policy, (5) changes in deferral accounting that increase the volatility of earnings and/or defer cash recovery of costs, and (6) elimination of Revenue Decoupling Mechanisms ("RDMs") or Rate Adjustment Mechanisms ("RAMs"). The PSC can initiate proceedings to prohibit Central Hudson from recovering from our customers the cost of service (including energy costs) that the regulators determine to have been imprudently incurred. In addition, the PSC could seek to impose substantial penalties on the Company for any violations of state utility laws, regulations, or orders.

- Political Environment: The political environment, at the local, national, and global level, may impact energy laws, governmental energy policies, or regulatory decisions. 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 Company may recover allowed costs. Political, economic, or social instability or events, trade disputes, increased tariffs, changes in laws, or the imposition of onerous regulations applicable to existing operations 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 condition.

- Policy/External Business Environment: The PSC announced the commencement of its Reforming the Energy Vision ("REV") initiative that aims to improve the efficiency of the electric system; reduce emissions; encourage greater development of clean generation, fuel diversity, and energy efficiency measures; and provide customers with knowledge and tools for more effective management of their total energy use through the adoption of new technologies on both the utility and customer side of the meter. Central Hudson expects to continue its efforts of working with the other New York electric utilities and various stakeholders in the energy industry to develop policy positions in order to facilitate the implementation of REV. In addition, CLCPA was passed by the New York State Senate and the New York State Assembly and includes renewable energy and emission reduction goals in New York State, which are among the most aggressive in the nation. The outcome of REV and the CLCPA and the many related proceedings cannot be predicted at this time, but they could result in an increased scope of regulated activities, potential for decreased earnings, and other risks.

Operational Risks:

- Facilities failure and/or damage: Central Hudson provides electricity and natural gas service to customers in its territory. Failure of, or damage to, facilities, or an error in operation or maintenance could result in bodily injury or death, property damage, the release of hazardous substances, or extended service interruptions. A natural disaster, such as a major storm, could impact Central Hudson's ability to access supplies and utilize critical facilities. Central Hudson's response to such events may be perceived to be below customer expectations. Central Hudson could incur substantial costs that may not be covered by Central Hudson's insurance policies or recovered through other regulatory mechanisms for storm preparation, to repair or replace facilities, compensate others for injury or death, or other regulatory penalties imposed by state utility regulators or other regulatory agencies. The occurrence of such events could also adversely affect the cost and availability of insurance.

- Cyber-attack: Central Hudson, as an operator of critical energy infrastructure, may face a heightened risk of cyber-attack. The Company, in addition to internal efforts, also engages third-party service providers to help facilitate the management of information security systems, communication tools, and data processing. In the event of a cyber-attack that Central Hudson and/or its third-party service providers were unable to defend or mitigate, operations could be disrupted, financial and other information systems could become impaired, property could be damaged, and customer and employee information could be stolen. Central Hudson could incur substantial cost for response, including repair to systems, litigation, and reputational damage, which may not be recoverable from customers.

- Processes/employee/contractor failure: the ability to effectively manage costs, is a key component of Central Hudson's strategy. The continued use of Lean Six Sigma techniques – a data-driven approach to develop processes that are faster, higher quality and less costly – to streamline existing business processes and foster innovation will play a critical role in managing the costs of doing business in a sustainable manner. The Company has developed business processes and uses information and communication systems and enterprise platforms for operations, customer service, legal compliance, personnel, accounting, planning, and other matters. Failure of the Company and/or its contractors to follow these business processes or information and communication systems, their unsafe actions, errors, or intentional misconduct, cyber incidents or attacks, or work stoppages could adversely affect the Company's operation and liquidity and result in substantial liability, higher costs, and increased regulatory requirements. The violation of laws or regulations by employees or contractors for personal gain may result from contract and procurement fraud, extortion, bribe acceptance, fraudulent related-party transactions, and serious breaches of corporate policy or standards of business conduct.

Environmental Risks:

- Environmental risks: Central Hudson is exposed to risks from the environmental consequences of its operations and the operations of its predecessors. Hazardous substances, such as asbestos, polychlorinated biphenyl ("PCB"), and coal tar have been used or produced in the course of Central Hudson's operations and are present on properties or in facilities and equipment currently or previously owned. To the extent not covered by insurance or recovered through rates, remediation costs, fines, judgments, and settlements could reduce earnings and cash flows.

Financial Risks:

- Supply Chain: Failure to eliminate or manage the constraints in the supply chain may impact the availability of items that are necessary to support normal operations as well as materials that are required for continued infrastructure growth and could have a material adverse effect on the Company.

- Interest Rate/Access to Capital: The Company has incurred material amounts of indebtedness. Ongoing access to cost-effective capital is required to fund 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 operation, regulatory environments including regulatory decisions regarding capital structure and allowed Return on Equity ("ROE"), capital market conditions, general economic conditions, credit ratings, and the environmental, social and governance profile of the Company. Rising interest environment impact new debt issuances and although interest costs are recovered through customer rates, they are impacted by regulatory lag. Higher finance costs could reduce earnings and significantly impact cash flow.

- Tax Laws: Earnings could be impacted by changes in income tax rates and other tax legislation. The nature, timing, or impact of changes in tax laws cannot be predicted and could have a material adverse effect. Although income taxes are generally recovered in customer rates, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods.

Other Risks:

- Reputational risk: There can be no assurance that internal policies, controls, or audits will ensure compliance with the Company'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. External stakeholders are increasingly challenging companies regarding climate change, sustainability, diversity, returns (including ROE and Return on Assets ("ROA")), executive compensation and other matters. Failure to effectively manage or respond to these risks could reduce earnings and significantly impact cash flow.

- Natural Gas Competitiveness: Government policy like the Draft Scoping Plan issued by the New York State Climate Action Council, could impact the competitiveness of natural gas business by developing policies to address climate change, in particular via the penetration of natural gas into new housing to address carbon intensity of the energy source. Local governments may also 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, or builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Company's ability to attract new natural gas customers or retain existing customers.

CH Energy Group - Regulated Operations - Central Hudson
Financial Highlights
Period Ended December 31

	Year to Date		
	2022	**2021**	**Change**
Electricity Sales (GWh) (1)	5,002	5,000	2
Natural Gas Sales (PJ) (2)	25.1	22.9	2.2
(In Millions)			
Revenues	$ 1,018.4	$ 796.2	$ 222.2
Energy supply costs - matched to revenues	402.6	227.0	175.6
Operating expenses - matched to revenues	116.6	100.3	16.3
Operating expenses - other	322.7	296.2	26.5
Depreciation and amortization	80.0	72.7	7.3
Other income, net	42.5	25.6	16.9
Interest charges	40.3	35.9	4.4
Income taxes	20.5	16.1	4.4
Net Income	$ 78.1	$ 73.6	$ 4.5

(1) GigaWatt hours ("GWh")

(2) Petajoule ("PJ")

Earnings: Central Hudson's earnings growth year over year is primarily due to the approved increase in delivery rates, which provides a return on additional capital invested in the business and recovery of operating and financing expenses. The earnings growth was partially offset by higher expenses and performance below customer service levels prescribed in the 2021 Rate Order related to the new CIS and financing costs above the amounts provided in rates associated with higher levels of working capital. Additionally, the Company recorded higher earnings adjustment mechanisms and earned incentives in the current year based on achieving certain targets and milestones associated with energy efficiency programs. Furthermore, 2021 earnings reflected the recording of regulatory deferrals for the future benefit to customers as a result of the failure to meet PSC prescribed targets for the System Average Interruption Frequency Index (“SAIFI”) and Customer Average Interruption Duration Index (“CAIDI”).

Energy supply costs reflect higher electric and natural gas commodity prices. This did not have a direct impact on earnings due to the full deferral of commodity costs. Central Hudson is authorized to bill customers volumetric factors for the recovery of bad debt and working capital costs related to commodity purchases, and fluctuations in volume and price will impact the revenues collected through these factors. However, the variation in revenues billed through these volumetric factors was not material.

During 2022, the suspension of collection activities since the beginning of the COVID-19 pandemic, coupled with the significant increase in electric and natural gas commodity costs in 2022, have resulted in a significant growth in our accounts receivable, thus increasing the level of working capital needed to currently support the business. The financing costs associated with this working capital are in excess of the amounts provided in rates and are not recoverable. Central Hudson continues to proactively contact customers regarding past due balances to advise them of financial assistance programs available and is also working with local agencies and municipalities to obtain funding for its customers which has been made available through federal and state programs. On June 16, 2022, the PSC approved Phase 1 of the Arrears Management Program in which residential utility customers who receive income-qualified government assistance for utility bills and other expenses and have past-due balances for service through May 1, 2022, had those balances forgiven. On January 19, 2023, the PSC approved Phase 2 AMP which applies to customers that were not eligible in Phase 1. Central Hudson has begun collection efforts for certain customers with large arrears balances through communications, urging payment and notifying customers that finance charges and termination efforts will be forthcoming. These efforts have generated some success with payments or payment arrangements. Central Hudson will continue its collection outreach efforts, expanding the number of customers and commencing finance charges and termination efforts in 2023. Under the terms of the 2021 Rate Order, Central Hudson is authorized to defer bad debt write-offs if they exceed 10 basis points above the amounts billed to customers through delivery rates and applicable surcharges. Therefore, uncollectible expense is not expected to have a significant impact on earnings. As of December 31, 2022, Central Hudson has deferred $4.1 million in uncollectible write-offs. While this deferral mechanism provides protection regarding the impact of bad debt expense on earnings, the growth in working capital associated with significantly higher accounts receivable arrears balances is causing liquidity pressure and has resulted in increased financing to support operations, which is not recoverable from customers. Regulatory action regarding Phase 2 arrears relief, along with Central Hudson’s continued collection efforts, particularly final termination and notices and locking service for non-payment, will provide visibility as to the timeframe over which the arrears growth will be resolved.

Electricity Sales

Electricity sales were relatively flat when compared to 2021. Higher retail sales to non-residential and interruptible customers were offset by lower sales to residential customers as customers transitioned back to pre-COVID consumption patterns. Year over year sales were also impacted by lower sales for resale.

Natural Gas Sales

Natural gas sales were higher year over year due to increases in sales to firm and interruptible customers resulting from colder winter weather. These increases were partially offset by lower sales for resale.

Depreciation and Amortization: Depreciation increased due to the increased investment in Central Hudson's electric and gas infrastructure and investments in information technology and common facilities in accordance with its capital expenditure program.

Other Income, net: The increase in other income is primarily due to a decrease in the non-service component of pension expense when compared to 2021.

Interest Charges: The increase in interest charges is primarily due to higher long-term debt and short-term borrowing balances.

Income Taxes: The increase in the combined effective tax rate is due to the timing of flow through tax items related to capital expenditures and unrealized book losses excluded for tax purposes. In addition, the increase in the effective tax rate for 2022 when compared to 2021 is primarily attributed to higher income before taxes at the statutory rate.

Central Hudson Revenues - Electric

Period Ended December 31

(In Millions)	Year to Date		
	2022	**2021**	**Change**
Revenues with Matching Expense Offsets:(1)			
Recovery of commodity purchases	$ 283.7	$ 161.1	$ 122.6
Sales to others for resale	39.8	17.6	22.2
Other revenues with matching offsets	72.5	72.9	(0.4)
Subtotal	396.0	251.6	144.4
Revenues Impacting Earnings:			
Customer sales	389.0	387.5	1.5
RDM and other regulatory mechanisms	(0.6)	(24.5)	23.9
Recovery of suspended COVID-19 finance charges	4.3	7.3	(3.0)
SAIFI & CAIDI	-	(5.0)	5.0
Incentives earned	5.7	2.3	3.4
Net plant and depreciation targets	(2.2)	(1.8)	(0.4)
Other revenues	5.4	6.4	(1.0)
Subtotal	401.6	372.2	29.4
Total Electric Revenues	$ 797.6	$ 623.8	$ 173.8

(1) Revenues with matching offsets do not affect earnings since they offset related costs, the most significant being energy cost adjustment revenues, which provide for the recovery of purchased electricity costs. Other related costs include certain authorized business expenses recovered through rates and the cost of special programs authorized by the PSC and funded with certain available credits. Changes in revenues from electric sales to other entities for resale also do not affect earnings since any related profits or losses are returned or charged, respectively, to customers.

Central Hudson Revenues - Natural Gas

Period Ended December 31

(In Millions)	Year to Date		
	2022	**2021**	**Change**
Revenues with Matching Expense Offsets:(1)			
Recovery of commodity purchases	$ 67.7	$ 40.6	$ 27.1
Sales to others for resale	11.5	7.8	3.7
Other revenues with matching offsets	4.7	6.4	(1.7)
Subtotal	83.9	54.8	29.1
Revenues Impacting Earnings:			
Customer sales	128.1	110.7	17.4
RDM and other regulatory mechanisms	4.4	0.3	4.1

Recovery of suspended COVID-19 finance charges	1.2	1.6	(0.4)
Incentives earned	0.5	1.2	(0.7)
Net plant and depreciation targets	(1.2)	(1.7)	0.5
Other revenues	3.8	5.5	(1.7)
Subtotal	136.8	117.6	19.2
Total Natural Gas Revenues	$ 220.7	$ 172.4	$ 48.3

(1) Revenues with matching offsets do not affect earnings since they offset related costs, the most significant being energy cost adjustment revenues, which provide for the recovery of purchased natural gas costs. Other related costs include certain authorized business expenses recovered through rates and the cost of special programs authorized by the PSC and funded with certain available credits. For natural gas sales to other entities for resale, 85% of such profits are returned to customers.

Central Hudson's revenues consist of two major categories: those that offset specific expenses in the current period (matching revenues) and those that impact earnings. Matching revenues represent amounts billed in the current period to recover costs for particular expenses (most notably, purchased electricity and purchased natural gas, major storm, pensions, and other post-employment benefits ("OPEB") and New York State energy efficiency programs). Any difference between these revenues and the actual expenses incurred is deferred for future recovery from or refund to customers, and therefore, does not impact earnings, with the exception of related carrying charges, which are recorded within other income or interest charges in the CH Energy Group and Central Hudson Statements of Income.

Electric Revenues:

The year over year increase in electric revenues is primarily due to increased commodity prices which are recovered from customers, as well as higher sales for resale. The year over year revenue increase also reflects the increases in delivery rates approved by the PSC effective July 1, 2022 and 2021, as well as, higher incentives earned for achieving certain targets and milestones associated with energy efficiency programs. 2021 revenues were reduced by regulatory deferrals recorded for SAIFI and CAIDI, which were above PSC prescribed targets. These reliability targets were both met in 2022. Additionally, 2021 revenues reflect a higher recovery of suspended finance charges due to the timing of the PSC approval of the 2021 Rate Order in the fourth quarter of 2021, which provided the retroactive recovery of these amounts through that date. In 2022, the recovery of suspended finance charges is recorded monthly up to the amounts included in the determination of delivery rates.

Natural Gas Revenues:

The year over year increase in natural gas revenues is primarily due to higher recovery of purchased commodity costs resulting from an increase in both sales volume and commodity price as well as higher sales for resale. Further impacting the year over year revenue increase is higher delivery rates effective July 1, 2022 and 2021. Partially offsetting these increases were lower amounts recorded for the recovery of suspended finance charges in 2022 when compared to prior year due to the timing of the related PSC approval.

Central Hudson Operating Expenses

Period Ended December 31

(In Millions)	Year to Date		
	2022	**2021**	**Change**
Expenses Currently Matched to Revenues:(1)			
Purchased electricity	$ 323.5	$ 178.7	$ 144.8
Purchased natural gas	79.3	48.6	30.7
Pension & OPEB	24.4	12.8	11.6
New York State energy efficiency programs	42.5	41.0	1.5

Major storm reserve	17.7	14.2	3.5
Energy affordability programs	10.1	11.0	(0.9)
Other matched expenses	21.7	21.0	0.7
Subtotal	519.2	327.3	191.9
Other Operating Expenses:			
COVID-19 related uncollectible reserve	-	0.8	(0.8)
Depreciation and amortization	80.0	72.7	7.3
Property and school taxes(2)	66.1	61.2	4.9
Weather related service restoration	5.4	8.2	(2.8)
Incremental resilience expense - Storm Isaias	-	1.5	(1.5)
Call center expense	8.4	4.6 (3)	3.8
Information technology ("IT")	24.4	16.3	8.1
Labor and related benefits	98.6	100.5	(1.9)
Uncollectible expense	8.2	5.3 (3)	2.9
Tree trimming	26.9	25.3	1.6
Other expenses	84.7 (3)	72.5 (3)	12.2
Subtotal	402.7	368.9	33.8
Total Operating Expenses	$ 921.9	$ 696.2	$ 225.7

(1) Includes expenses that, in accordance with the 2018 and 2021 Rate Orders, are adjusted in the current period to equal the revenues billed for the applicable expenses and the differences are deferred.
(2) In accordance with the 2018 and 2021 Rate Orders, Central Hudson is authorized to continue to defer for the benefit of or recovery from customers 90% of any difference between actual property tax expense and the amounts provided in rates for each Rate Year. Central Hudson's portion is limited to 5 basis points, with a maximum of approximately $0.6 million, pre-tax per Rate Year.
(3) Certain expenses reported for the twelve months ended December 31, 2021 have been reclassified to "Call center expense" and "Uncollectible expense" to conform to the current period presentation.

Operating Expenses:

The year over year increase in operating expenses is primarily the result of higher commodity costs for both electric and natural gas. The increase in other operating expenses is attributed to increases in certain expenses as provided for in delivery rates including depreciation, property and school taxes, tree trimming and uncollectible expense. Further impacting the increase in operating expenses were higher IT and customer service expenses related to the new Customer Information System ("CIS"). These increases were partially offset by lower weather-related restoration costs and lower labor-related expenses in the current year.

Variations in purchased natural gas and electricity costs and other expenses currently matched to revenues do not have a direct impact on earnings due to Central Hudson's regulatory mechanism for the full deferral of these expenses.

Financial Position

CH Energy Group – Regulated – Central Hudson
Significant Changes in the Balance Sheets
For the twelve months ended December 31, 2022

(In Millions)

Balance Sheet Account	Increase (Decrease)	Explanation
Accounts receivable, net of allowance for uncollectible accounts	$96.1	Increase is primarily due to the suspension of collection efforts required during the COVID pandemic, which impacted customers' payment behavior, increased commodity prices, and higher seasonal winter energy usage in the fourth quarter.

Other receivables	8.6	Increase is primarily related to billings for attachments rents, mutual aid efforts, and contributions in aid of construction.
Fuel, materials, and supplies	7.1	Increase is due to rising costs and purchases of materials and supplies in an effort to minimize impacts of supply chain interruptions.
Regulatory assets - current	47.1	Increase is primarily driven by higher electric and natural gas commodity costs and higher unrealized mark-to-market losses on derivative contracts. Further contributing to the increases are higher credits provided to customers in 2022 upon the approval of AMP Phase 1 which will be recovered through a surcharge in 2023 and higher electric and natural gas RDMs for actual billed revenues below the prescribed targets.
Special deposits and prepayments	6.5	Increase is primarily due to the prepayment of a natural gas storage agreement.
Regulatory assets - long term	51.6	Increase is primarily related to costs incurred for major storm restoration in excess of the rate allowance along with an increase in spending associated with the energy efficiency heat pump programs and higher deferred taxes recoverable through future rates attributable to plant, partially offset by rate allowance billed in excess of amounts spent for environmental remediation in 2022.
Prefunded pension costs	(10.9)	Decrease is primarily driven by the significant trust asset investment losses in 2022, partially offset by the impact of the increase in the discount rate on plan liabilities.
Other assets - long term	(8.5)	Decrease reflects amounts drawn from restricted cash held in escrow for work performed related to a System Deliverability Upgrade ("SDU") project.
Long term debt, including current maturities	196.6	Increase is due to issuances of long-term debt in 2022, partially offset by the repayment of matured debt.
Accounts payable	17.0	Increase is primarily driven by higher costs associated with purchased natural gas and electric commodity costs driven by both price and volume towards the end of the year.
Regulatory liabilities - current	11.6	Increase is primarily due to higher bill credits to be provided to customers per the 2021 Rate Order, partially offset by payments to NYSERDA for the Clean Energy Fund (“CEF”) initiatives in excess of amounts collected.
Fair value of derivative instruments - current liabilities	6.5	Increase in liabilities is due to higher unrealized mark-to-market losses related to open electric and natural gas derivative contracts.
Regulatory liabilities - long term	(9.8)	Decrease is primarily due to bill credits provided to customers per the 2021 Rate Order and to the amortization of plant related deferred tax liabilities as a result of the Tax Cuts and Jobs Act.
Regulatory liabilities- related to pension and OPEB costs	(22.4)	Decrease is primarily due to a net decrease in the projected benefit obligation resulting from an increase in the discount rate, partially offset by net investment losses on the pension and OPEB plan assets.
Other liabilities - long term	(14.2)	Decrease is primarily due to a reduction of amounts held in escrow for a SDU project along with reduced liability resulting from participant investment losses in the directors' and officers' deferred compensation plan.
Accumulated deferred income taxes	29.7	Increase is primarily due to the accounting requirement to recognize deferred taxes for the difference between tax basis of assets and liabilities and the book basis. These amounts are fully deferred for future return to or recovery from customers.

Liquidity and Capital Resources

CH Energy Group - Regulated, Non-regulated and Holding Company Summary of Cash Flow
Period Ended December 31
(In Millions)

	Year to Date	
	2022	**2021**
Cash, cash equivalents and restricted cash - beginning of period	$ 18.1	$ 12.8
Cash from operations pre-working capital	98.2	158.4
Working capital	(132.5)	(97.5)
Operating Activities	(34.3)	60.9

Investing Activities		(224.6)		(240.3)
Financing Activities		245.8		184.7
Cash, cash equivalents and restricted cash - end of period	$	5.0	$	18.1

Operating Activities: The decrease in cash from operations pre-working capital in 2022 as compared to 2021 was primarily attributable to increased storm restoration costs. Additionally, 2021 cash from operations pre-working capital included cash received in other advances and held in escrow for a future project while 2022 reflects the use of this cash for work completed. The decrease in pre-working capital was partially offset by the increase in delivery rates, which provided earnings on rate base growth and lower spending on related heat pump programs. The decrease in cash flow related to working capital in 2022 was primarily attributable to an increase in accounts receivable balances as previously discussed, coupled with higher electric energy and natural gas commodity costs, partially offset by a reduction in the amount returned to customers through the RDM in 2022, as compared to 2021.

Investing Activities: Cash used in investing activities during 2022 were lower than 2021 due to lower software investments following the implementation of Central Hudson's new CIS system in September 2021. Other investing activity in 2022 includes proceeds from the sale of utility assets to Transco, offset by CHET's increased investment in Transco. In 2021, other investing activity consisted of Central Hudson's contributions to the Supplemental Executive Retirement Plan Trust, as required by the Trust Agreement, of $8.1 million. No such funding requirement was needed in the current year.

Financing Activities: The increase in cash from financing activities was primarily related to the issuance of $110 million of long-term debt and $45 million in capital infusions to supplement the cash from operations and fund the capital investment program. Short term borrowings have remained at elevated levels due to the sustained higher levels of working capital.

Anticipated Sources and Uses of Cash

CH Energy Group's cash flow is primarily generated by the operations of its utility subsidiary, Central Hudson. Generally, Central Hudson does not accumulate significant amounts of cash but rather re-invests its earnings into future capital investments and distributes excess cash to CH Energy Group in the form of dividends or receives capital contributions from CH Energy Group to meet equity financing needs.

Central Hudson expects to fund capital expenditures with cash from operations, a combination of short-term and long-term borrowings and equity infusions. Central Hudson may alter its plan for capital expenditures as its business needs require. Central Hudson intends to fund growth in its long-lived assets in a manner that maintains an equity ratio aligned with its delivery rates.

Central Hudson utilizes short-term debt to fund seasonal and temporary variations in working capital requirements. Delays in collections of accounts receivable from customers, combined with increased wholesale energy prices and higher seasonal winter energy consumption experienced this year, have all contributed to the significant increase in working capital in 2022. Central Hudson has begun collection efforts for certain customers with large arrears balances. Continued collection efforts, along with potential future state initiatives, are expected to provide visibility into the resolution of the arrears issue. At this time, it is uncertain what level of arrears will be paid by customers through collection efforts, what portion of customers will enter into deferred payment arrangements and what portion may be determined to be uncollectible and recorded as a regulatory asset under the terms of our current rate agreement. The time period associated with the collection of the regulatory assets or deferred payment arrangements will be factored into our future financing plans. Short-term debt will be used to supplement liquidity until customer payment behaviors and commodity prices stabilize.

Central Hudson's secondary sources of funds are its cash reserves and credit facilities. Central Hudson's ability to use its credit facility is contingent upon maintaining compliance with certain financial covenants. Central Hudson does not anticipate that those covenants will restrict its access to funds in 2023 or the foreseeable future.

Despite the economic challenges noted, Central Hudson has not experienced any issues with accessing capital markets during the pandemic or thereafter, having successfully secured new financing in recent years, as well as during 2022, and has no concerns over accessing capital markets in the foreseeable future. Central Hudson's 2021 Rate Order was effective July 1, 2021 and management took initiatives to mitigate the impact of new rates on customers during this difficult economic environment as illustrated by the rate decrease in the first year of the 2021 Rate Order for electric delivery revenues. The increase in rates over the subsequent two years should continue to provide the necessary cost recovery to ensure safe and reliable service, as well as a reasonable rate of return on Central Hudson's investment.

At this time, CH Energy Group believes cash generated from operations and funds obtained from equity infusions from Fortis, as well as its financing program, will be sufficient for the foreseeable future to meet working capital needs, fund Central Hudson's capital program, fund CHET's current investment obligations in Transco and meet Central Hudson's public service obligations and growth objectives.

Committed Credit Facilities

The PSC issued a Financing Order, effective November 22, 2021, authorizing Central Hudson to enter into multi-year credit agreements in an aggregate amount not to exceed $250 million; and approval to issue and sell new long-term debt from time to time through December 31, 2024, in an aggregate amount not to exceed $445.7 million, including up to $412 million for traditional utility purposes and $33.7 million to refinance its variable interest debt.

On April 4, 2022, Central Hudson entered into a first amendment to the March 2020 Central Hudson credit agreement with five commercial banks. The amendment replaces LIBOR with a benchmark replacement interest rate and increases the aggregate commitment by the lenders by $50 million, making the aggregate amount of total commitments equal to $250 million. The credit agreement as amended has a five-year term, maturing in March 2025. Proceeds received from the revolving credit agreement are used for working capital needs and for general corporate purposes. Letters of credit are available up to $15 million from three participating banks. The credit facility is subject to certain covenants and certain restrictions and conditions, as well as Central Hudson is required to pay a commitment fee calculated at a rate based on the applicable Standard and Poor's ("S&P") or Moody's rating on the average daily unused portion of the credit facility.

At December 31, 2022, there were $90 million in borrowings outstanding under Central Hudson's committed credit arrangements. At December 31, 2021, there were $100 million in borrowings outstanding under Central Hudson's committed credit arrangements.

Uncommitted Credit

At December 31, 2022, CH Energy Group and Central Hudson had $10 million and $60 million respectively, in uncommitted short-term credit arrangements with four commercial banks, with outstanding borrowings of $15 million under Central Hudson's uncommitted credit agreements.

On November 4, 2022, CH Energy Group entered into a $10 million, short-term credit agreement with a commercial bank to provide liquidity to meet short term cash needs.

On December 15, 2022, Central Hudson entered into a new $30 million, short-term uncommitted credit agreement with a commercial bank not included in its current credit facility to provide additional liquidity to its existing portfolio. Proceeds received from the new credit agreement are to be used for working capital needs and for general corporate purposes.

At December 31, 2021, there were no short-term credit arrangements for CH Energy Group. Central Hudson had uncommitted short-term credit arrangements with two commercial banks totaling $30 million. CH Energy Group and Central Hudson had $7 million in borrowings outstanding under Central Hudson's uncommitted credit agreements.

Central Hudson's Bond Ratings

	December 31, 2022		December 31, 2021	
	Rating(1)	**Outlook**	**Rating(1)**	**Outlook**
S&P	BBB+	Stable	A-	Stable
Moody's	Baa1	Stable	Baa1	Stable
Fitch	A-	Stable	A-	Stable

(1) These senior unsecured debt ratings reflect only the views of the rating agency issuing the rating, are not recommendations to buy, sell, or hold securities of Central Hudson and may be subject to revision or withdrawal at any time by the rating agency issuing the rating. Each rating should be evaluated independently of any other rating.

On January 20, 2023, Fitch affirmed the (A-) rating of Central Hudson's senior unsecured debt and changed its rating outlook from stable to negative. Fitch indicated Central Hudson's rating reflects the low-risk nature of its regulated electric and gas utility operations. However, the negative outlook reflects Fitch's concerns regarding the credit supportiveness of the PSC, with particular regard to the outcome of the Company's next rate case to support future credit metrics consistent with Central Hudson's current rating.

On December 1, 2022, S&P lowered the rating of Central Hudson's senior unsecured debt from (A-) to (BBB+) and changed its rating outlook from negative to stable. S&P indicated that the downgrade reflects the weakening of the Company's financial measures driven by the effects of rising inflation and higher interest rates, as well as the company's elevated capital expenditure and increasing operating expenses. In addition, S&P cited that Central Hudson's 2021 Rate Order is restraining to cash flows, which further weakens the Company's financial measures. On November 30, 2021, Fitch affirmed its rating (A-) and stable outlook. On September 22, 2021, Moody's downgraded Central Hudson's senior unsecured credit rating from A3 with a negative outlook to Baa1 with a stable outlook.

Central Hudson meets its need for long-term debt financing through privately placed debt. As a regulated electric and natural gas utility company, Central Hudson is required to obtain authorization from the PSC to issue debt securities with maturities greater than 12 months.

On September 28, 2022, Central Hudson issued $100 million of Series Y, 10-year Senior Notes with an interest rate of 5.07% per annum and a maturity date of September 28, 2032 and $10 million of Series Z, 30-year Senior Notes with an interest rate of 5.42% per annum and a maturity date of September 28, 2052. Central Hudson used the proceeds from the sale of the Senior Notes for general corporate purposes, including the repayment of short-term debt.

On January 27, 2022, Central Hudson issued $50 million of Series W, 5-year Senior Notes with an interest rate of 2.37% per annum and a maturity date of January 27, 2027 and $60 million of Series X, 7-year Senior Notes with an interest rate of 2.59% per annum and a maturity date of January 27, 2029. Central Hudson used the proceeds from the sale of the Senior Notes for general corporate purposes, including the repayment of $23.4 million of maturing debt on April 1, 2022.

Central Hudson’s strong investment-grade credit ratings help facilitate access to long-term debt; however, management can make no assurance that future financing will be available or economically reasonable.

CH Energy Group and Central Hudson’s capital structure is as follows *(Dollars in Millions)*:

CH Energy Group

	December 31, 2022		December 31, 2021	
		%		%
Long-term Debt[1]	$ 1,126.1	48.9	$ 931.5	47.1
Short-term Debt	105.0	4.5	107.0	5.4
Common Equity	1,073.0	46.6	939.3	47.5
Total	$ 2,304.1	100.0	$ 1,977.8	100.0

(1) Includes current maturities of long-term debt.

Central Hudson

	December 31, 2022		December 31, 2021	
		%		%
Long-term Debt[1]	$ 1,119.4	49.1	$ 922.8	47.0
Short-term Debt	105.0	4.6	107.0	5.5
Common Equity	1,056.4	46.3	932.2	47.5
Total	$ 2,280.8	100.0	$ 1,962.0	100.0

(1) Includes current maturities of long-term debt.

In accordance with the 2021 Rate Order, Central Hudson's customer rates continued to be premised on a capital structure, excluding short-term debt, with a common equity ratio of 50%, 49% and 48% for the rate years beginning July 1, 2021, July 1, 2022, and July 1, 2023, respectively. Central Hudson is currently managing its financing to maintain a common equity ratio at 48%.

CH Energy Group and Central Hudson believe they will be able to meet their short-term and long-term cash requirements, given the flexibility awarded under the 2021 Rate Order, including a ROE of 9.0%.

Critical Accounting Estimates

The preparation of Central Hudson’s consolidated financial statements requires management to make estimates that affect the reported amounts of assets, liabilities, revenue and expenses, and the related disclosure of contingent assets and contingent liabilities. Estimates are based on the Company’s historical experiences and on various other assumptions that it believes are reasonable under the circumstances, the results of which form the basis for making estimates about the carrying values of assets and liabilities. The accuracy of these estimates and the likelihood of future changes depend on a range of possible outcomes and several underlying variables, many of which are beyond the Company’s control. Actual results may differ from these estimates under different assumptions or conditions.

Central Hudson believes the following judgments and estimates are critical in the preparation of its consolidated financial statements.

- Central Hudson is subject to cost-based rate regulation. As a result, the effects of regulatory actions are required to be reflected in the financial statements. Regulatory accounting guidance results in differences in the application of generally accepted accounting principles between regulated and non-regulated businesses and requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as expenses or revenues in non-regulated businesses. Management periodically assesses whether the regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory and political environments, the ability to recover costs through regulated rates, recent rate orders to Central Hudson and other regulated entities, and the status of any pending or potential deregulation legislation. Based on this assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state and federal levels and is subject to change in the future. If future recovery of costs ceases to be probable, the regulatory asset would be written-off, which would materially impact earnings. Additionally, regulatory agencies can provide flexibility in the manner and timing of recovery of regulatory assets.

- Depreciation and amortization are based on estimates of the useful lives and estimated net salvage value of properties.
- Estimates for uncollectible accounts are based on customer accounts receivable aging data as well as consideration of various quantitative and qualitative factors, including special collection issues, a historical analysis of the relationship of write-offs to accounts receivable balances in arrears, and estimated impacts of the current and future economic conditions.
- The tax reserve recorded by Central Hudson relates to a change in 2010 to its tax return methodology for claiming deductions for incidental repair and maintenance expenditures on its utility assets. Although management believes that its methodology for claiming the deduction is consistent with the Internal Revenue Code and case law, management cannot predict whether the Internal Revenue Service will accept the entirety of the deduction claimed.
- The estimates for other operating reserves are based on assessments of future obligations related to injuries and damages and workers' compensation claims.
- Unbilled revenues are determined based on the estimated sales for services rendered to customers whose meters are not read on the last day of the month.
- The significant assumptions and estimates used to account for the pension plan and OPEB benefit expenses and liabilities are the discount rate, the expected long-term rate of return on the Retirement Plan and OPEB plans assets, the rate of compensation increase, the healthcare cost trend rate, mortality assumptions, and the method of amortizing gains and losses.
- Estimates are also reflected for certain commitments and contingencies where there is sufficient basis to project a future obligation, including environmental remediation costs and NRAs.

Changes in Internal Controls over Financial Reporting

There have been no changes in internal controls over financial reporting for CH Energy Group of Central Hudson during the twelve months ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Regulatory Proceedings

<u>2021 Rate Order</u>

On November 18, 2021, the PSC issued an Order Approving Rate Plan in Cases 20-E-0428 and 20-G-0429, the ("2021 Rate Order"). The 2021 Rate Order adopts the terms set forth in the August 24, 2021 Joint Proposal. The 2021 Rate Order also fully resolves all issues and concerns raised and/or asserted, or that could have been raised and/or asserted in the Sales Tax Refund Proceeding (Case 20-M-0134). The 2021 Rate Order was effective December 1, 2021 and includes a make-whole provision that provides new rates to become effective retroactive to July 1, 2021, with Rate Year ("RY") RY1, RY2, and RY3 defined as the twelve months ending June 30, 2022, June 30, 2023, and June 30, 2024, respectively.

The 2021 Rate Order provides electric delivery revenue (decreases)/increases of $(3.1) million, $19.5 million and $20.7 million in RY1, RY2 and RY3, respectively and natural gas delivery revenue increases of $4.7 million, $6.3 million and $6.4 million in RY1, RY2 and RY3, respectively. The 2021 Rate Order also provides electric bill credits of $(2.0) million in RY1, $9.5 million in RY2, and $21.5 million in RY3; and gas bill credits of $0.8 million in RY1, $3.2 million in RY2 and $5.6 million in RY3.

The Company's electric and natural gas revenue requirements reflect a common equity ratio of 50% for RY1, 49% for RY2 and 48% for RY3 and a ROE of 9.0%. Earnings above 9.5% and up to 10.0% will be shared 50% / 50% between the shareholder and ratepayers. Earnings above 10.0% and up to 10.5% will be shared 25% / 75% between the shareholder and ratepayers. Earnings above 10.5% will be shared 10% / 90% between the shareholder and ratepayers.

The 2021 Rate Order utilizes existing regulatory balances to reduce bill impacts for customers during the term of the agreement. The 2021 Rate Order also reflects a postponement of certain capital projects, as well as reductions to O&M costs to help manage customer bill impacts. The total electric revenue (decrease)/increase (after bill credits) is (0.2)%, 1.2%, and 1.2% for RY1 through RY3, respectively, and the total natural gas revenue increase (after bill credits) is 1.9%, 1.8%, and 1.8% for RY1 through RY3, respectively.

The 2021 Rate Order:

- establishes the Company's future energy infrastructure investments, programs and operations;
- stabilizes electric delivery rates in the first year with a slight decrease for residential customers;
- reflects modest increases in gas delivery rates producing bill impacts just under two percent each RY;
- includes increased electric bill discounts for income qualified households and expanded access into Central Hudson's Energy Affordability Program;
- reflects investments in clean energy efficiency ground and air-source electric heat pumps, electric vehicle charging, and system upgrades that support utilization of renewable sources;
- implements ten Earnings Adjustment Mechanisms which reflect a maximum earnings potential of 100 basis points;
- maintains the current Customer Average Interruption Duration Index metric and reflects increasingly stringent System Average Interruption Frequency Index targets, continues and further enhances existing gas safety performance metrics and public safety programs, and includes higher performance requirements for Customer Service Performance Indicators with a net increase in total potential NRAs;
- provides Central Hudson with necessary resources to support ongoing O&M and necessary investments to reinforce electric and gas system reliability and resiliency through storm hardening, expanded vegetation management/tree trimming, continued investment for LPP replacement or elimination, and deployment of new technologies, as well as IT systems to further protect against cyber security risks and;
- includes several deferrals that provide the Company authorization to defer COVID-19 Incremental O&M Costs net of savings, lost revenues (finance charges and reconnection fee revenues), and uncollectible write-offs.

Central Hudson 2021 Financing Order

On November 18, 2021, the PSC approved the Company's request under Section 69 of the Public Service Law authorizing Central Hudson to enter into multi-year credit agreements in an aggregate amount not to exceed $250 million; and approval to issue and sell new long-term debt from time to time through December 31, 2024, in an aggregate amount not to exceed $445.7 million, including $412 million for traditional utility purposes and up to $33.7 million to refinance its variable interest debt. Central Hudson filed a letter indicating its unconditional acceptance of the November 18, 2021, Order on December 6, 2021.

FERC SDU Proceeding
On December 31, 2019, Central Hudson submitted to FERC a new rate schedule pursuant to Rate Schedule 12 of the NYISO Open Access Transmission Tariff (“OATT”) to establish a Facilities Charge for SDUs being installed on Central Hudson’s transmission facilities, which are required to provide four Large Generating Facility Developers with Capacity Resource Interconnection Service. This charge provides Central Hudson with full recovery of all reasonably incurred costs related to the development, construction, operation, and maintenance of the SDU and a reasonable return on its investment. Project costs to be recovered by Central Hudson and allocated to the Load Serving Entities pursuant to Rate Schedule 12 of the NYISO OATT are expected to be approximately $2.6 million plus operation, maintenance and other applicable costs and will be updated annually. The parties submitted an Offer of Settlement with the FERC on June 30, 2021, which included an updated ROE of 9.4% plus a 50-basis point adder for a total ROE of 9.9%. The settlement was subsequently approved by FERC on October 4, 2021.

August 2020 Tropical Storm Isaias
On August 5, 2020, the New York State Governor instituted proceeding 20-01633 directing the PSC to initiate an investigation of certain New York State utilities’ responses to Tropical Storm Isaias, which impacted Central Hudson’s service territory on August 4, 2020. On November 19, 2020, DPS issued an interim Storm Report setting forth preliminary findings, including purported failures by the identified utilities to comply with their respective PSC approved Emergency Response Plans and Show Cause (“Storm Show Cause Order”) that initiated proceedings against Central Hudson and the other utilities. The Show Cause Order identified 32 apparent violations by Central Hudson, which, if established, could have resulted in up to $16 million of penalties. Central Hudson filed its response to the Show Cause Order on December 21, 2020. The Company performed a thorough investigation and as indicated in its response, believed no penalty should be issued because the facts demonstrated that Central Hudson fully complied with its PSC-approved Emergency Response Plan, which served as the standard against which Central Hudson should be evaluated. On February 23, 2021, Central Hudson filed a Notice of Impending Settlement Negotiations. On July 7, 2021, Central Hudson and DPS entered into a Settlement Agreement, which included a commitment by Central Hudson to establish a $1.5 million regulatory liability to be used by Central Hudson to support or advance storm restoration and/or electric system resiliency and reliability in excess of amounts funded by customers. The PSC approved the Settlement Agreement within the Order Granting Motion and Adopting Settlement Agreement on July 15, 2021. The Settlement Agreement does not include any finding or admission of any violation by Central Hudson, and it specifies that the settlement amount is not a penalty. Central Hudson has fulfilled the Settlement Agreement.

Winter Storm Landon
In compliance with 16 NYCRR Part 104, Central Hudson submitted its Emergency Response Performance Assessment (“scorecard”) on March 10, 2022, regarding Winter Storm Landon that occurred in New York State on February 4, 2022. On March 16, 2022, the Commission announced in a press release that it will be overseeing an examination of Central Hudson’s actions during Winter Storm Landon, including a thorough review of the scorecard submitted on March 10, 2022, and determine any next steps. On April 8, 2022, Central Hudson also submitted its Part 105 Preparation and System Restoration Report. This examination has now concluded and DPS Staff has communicated to Central Hudson that they have found no issues.

Inflation Reduction Act of 2022
In August 2022, the President of the United States of America signed into law the Inflation Reduction Act (“IRA”) of 2022, which enacted a number of changes to federal tax law. These changes include the introduction of a new 15% corporate minimum tax on applicable corporations, including CH Energy Group, effective for tax years beginning after December 31, 2022. Enactment of the new law has not impacted our financial condition, results of operations or cash flows for the period ended December 31, 2022. Central Hudson does not expect a material impact on future results due to the implementation of

the corporate minimum tax or any other aspect of the Act. The IRA also includes numerous tax credits which currently do not apply and any that may apply in the future are expected to have an immaterial impact.

Sale of Utility Asset to Transco

On June 21, 2022, the PSC issued Order Authorizing the Transfer of Transmission Property and Easement Interest under Case 22-E-0077. The Order was approved to increase the power transfer capability from upstate to downstate New York. In the Order, the PSC authorized the transfer of easement interest covering real property associated with a 12-mile overhead 115 kV electric transmission line ("SL Line") and certain transmission property and equipment related to the Sugarloaf Switching Station and the SL Line, from Central Hudson to New York Transco LLC and the recognition of any gains realized upon the transfer for the benefit of customers. On July 11, 2022, Central Hudson completed the sale of transmission property and easement interest for approximately $4.6 million with a realized gain of $4.4 million which was deferred as a regulatory liability for the benefit of customers with carrying charges at the Company's pre-tax weighted average cost of capital as prescribed by the Order.

The below matters are ongoing regulatory proceedings. We cannot predict the ultimate outcome or whether these proceedings would potentially impact Central Hudson in the future. Should it become reasonably possible or probable in the future that a loss will be sustained from any of the below proceedings, disclosure that it is reasonably possible or an accrual of the probable amount of loss will be made consistent with our accounting policies.

Investigations and Inquiries into Central Hudson's Customer Information System and Billing Practices

On September 1, 2021, Central Hudson launched its new CIS. The system replaced the Company's 40-year-old legacy mainframe system and was implemented after careful due diligence, planning, and investigation to address critical obsolescence and cyber security risks. The new CIS enables Central Hudson to provide creative solutions for our customers and adapt to evolving technology.

After implementation, technical issues arose relating primarily to overlapping complex billing transactions. As a result, a portion (approximately 7%) of Central Hudson customers experienced delays in their bills in the months following the implementation. In certain cases, customers received bills that required adjustments, which did not have a material adverse impact to Central Hudson's financial statements. Remediation of these billing issues has been a top priority across the Company. The amounts that were not billed have been recorded within the RDM or as unbilled revenue. A significant force of external resources was also retained by the Company to support stabilization of the billing processes.

CIS Show Cause Order

During the March 2022 PSC session, the PSC directed Department of Public Service ("DPS") Staff, and subsequently instituted Case 22-00666, to investigate billing issues subsequent to the implementation and to publicly track comments and other related documents. The Company has answered several data requests regarding the CIS implementation and continues to collaborate with DPS Staff. On December 15, 2022, the PSC issued its Order to Commence Proceeding and Show Cause, under Case 22-M-0645. The Order discussed issues related to the CIS project, including system defects, training, testing, staffing, and cited alleged apparent violations of Public Service Law, New York Codes, Rules and Regulations, and prior PSC Orders. Central Hudson filed its response on January 17, 2023, acknowledging the unintended disruptive impact on customers and stating that the Company did not violate the Public Service Law ("PSL"), rules, or Commission Orders and that neither penalties under PSL §§ 25, 25-a nor a prudence review is warranted. Central Hudson cited in its response its legal position that the Office of Investigation and Enforcement report misinterpreted or misapplied specific sections of statutes, rules, and Commission Orders.

Agway Energy Services LLC Petition ("Agway")
On February 25, 2022, Agway filed a Petition for Declaratory Ruling and Corrective Action Plan Concerning Failure of Central Hudson Gas and Electric Corporation to provide accurate Electronic Data Interchange information or provide accurate client bills ("Petition"). Agway is a licensed Energy Service Company ("ESCO") that supplies energy for approximately 1,035 customers in Central Hudson's service territory. The Petition alleges impacts to Agway's business related to Central Hudson's billing system transition and alleges violations of the Uniform Billing Practices ("UBP") and that Central Hudson breached the Billing Services Agreement ("BSA"). Agway requested that the PSC investigate these issues, declare violations, order that Central Hudson resolve these violations in a timely manner, appoint an independent monitor to oversee the resolution, disgorge incurred fees, and award compensatory damages.

On March 18, 2022, Central Hudson filed its Verified Motion to Dismiss and Opposition to the Petition of Agway for a Declaratory Ruling ("Motion"). The Motion argues that the Petition should be dismissed because it is not a proper Petition for Declaratory Ruling because it fails to seek a PSC interpretation to a statute or rule and is deficient because it fails to allege a specific violation of either the UBP or BSA. Central Hudson's Motion also argues that it is improper or Agway to seek compensatory damages as damages are limited pursuant to the BSA and outside of the PSC's jurisdiction to provide. Agway has submitted a filing requesting to enter mediation on this matter, including recurring meetings with both parties and DPS Staff. On June 24, 2022, the Company entered mediation with Agway and continues to hold weekly meetings to discuss, investigate, and resolve issues.

New York State Senate Investigation regarding Commodity Prices and Billing System Transition
On April 13, 2022, Central Hudson and all New York utilities received notice from the New York State Senate that it is investigating the winter electric and gas commodity price increases and Central Hudson's billing system issues. On December 31, 2022, the Committee on Investigation and Government Operations filed their Final Investigative Report on Utility Pricing Practices and Failures and made recommendations based on their findings.

New York State Office of the Attorney General Billing System Inquiry
On May 17, 2022, Central Hudson received inquiries from the New York State Office of the Attorney General ("AG's Office") seeking information regarding recent changes to Central Hudson's billing practices and systems and complaints that the AG's Office has received from Central Hudson's customers. Central Hudson has responded to these inquiries, as well as additional inquiries and data requests from the AG's Office. Central Hudson continues to have regular discussions with the AG's Office regarding the billing system and the data requests.

Energy Affordability & COVID-19 Proceeding
On June 11, 2020, the PSC established a new proceeding, Case 20-M-0266, to identify and address the effects of the COVID-19 pandemic on utility service in New York State, including all entities subject to PSC jurisdiction or permitting authority. The proceeding included, but is not limited to, impacts on rate-setting, rate design, utility financial strength, low-income programs, collections and termination of service ensuring the provision of safe and adequate service at just and reasonable rates in recognition of the ramifications from the COVID-19 pandemic and the extent to which the PSC's clean energy programs should be maintained or accelerated.

On February 4, 2021, Staff issued a whitepaper on New York State Energy Affordability Policy ("EAP"), Case 14-M-0565, proposing potential modifications and improvements to the distribution utility's energy affordability program for low-income customers. On August 12, 2021, the PSC issued an Order adopting EAP modifications, establishing an EAP Working Group, and directing the Utilities to file several compliance filings. Central Hudson is an active participant in the EAP working group which continues to address various aspects of the Order, including the development of an Arrears Relief Program designed to forgive a portion of the utility arrears accrued during the COVID-19 pandemic.

On April 7, 2022, $250 million was approved in the New York State budget to provide funding for utility arrears relief for customers eligible for energy affordability programs. The Energy Affordability Policy ("EAP") Working Group developed and filed a report on May 23, 2022, which proposed a comprehensive arrears relief program for customers to be rolled out in two phases. Phase 1 would address all existing low-income customers' arrears and Phase 2 would be a broader program focused on arrears relief for residential customers that did not meet the definition of low-income, as well as some non-residential customers. On June 16, 2022, the PSC approved Phase 1 of the AMP, whereby residential utility customers who receive income-qualified government assistance for utility bills and other expenses and have past-due balances for service through May 1, 2022, will have those balances forgiven. The Phase 1 program was funded in part through the $250 million in New York State relief, $2.8 million of which was dispersed to Central Hudson. The remainder of the program cost is being recovered through a temporary surcharge on utility bills not to exceed a 0.5% bill impact for residential customers. As of December 1, 2022, Central Hudson had distributed approximately $7.1 million in relief via bill credits to roughly 5,600 eligible customers. Additional bill credits will be processed in early 2023 as new customers become eligible for relief through the end of 2022.

On January 19, 2023, the PSC issued Order for Phase 2 AMP providing arrears relief for certain residential and small commercial customers with arrears balances as of May 1, 2022, which were not eligible for Phase 1. The arrears amounts will be filed with Staff by February 18, 2023, together with the Phase 2 Outreach and Education Plans. The Company was directed to utilize deferred economic development balances to offset a portion of the program cost.

Columbia Energy Notice

Columbia Energy, one of the ESCOs operating in Central Hudson's service territory, filed notice with the New York State Public Service Commission that it intended to return its approximately 25,000 customers to Central Hudson's commodity supply service. Certain municipalities and the municipalities' Community Choice Aggregation ("CCA") administrator filed a petition with the New York Supreme Court in Albany seeking a temporary restraining order ("TRO") alleging Columbia Energy breached its contractual obligations to provide commodity service to CCA customers. The TRO is a preliminary step necessary before the Supreme Court may grant a permanent injunction. The Supreme Court granted the TRO. Columbia Energy subsequently defaulted on its obligations to the NYISO, and as such, the NYISO ordered Central Hudson to return Columbia Energy's customers (who are also the CCA customers) to Central Hudson's commodity supply service as of July 19, 2022. As of November 2022, Central Hudson has processed the return of the customers to Central Hudson's commodity supply service. The parties to the Supreme Court case have filed a motion in the Supreme Court alleging that Columbia Energy's default to NYISO was a breach of the TRO previously granted by the Supreme Court. That litigation is ongoing and Central Hudson is not a party.

Central Hudson Management and Operations Audit

On December 16, 2021, the PSC instituted a proceeding for a new Central Hudson audit in its Order Initiating a Management & Operations Audit. The audit is being conducted by an independent auditor selected by DPS Staff as announced at the March 2022 PSC session. The scope of the audit includes issues from the previous audit for follow-up, as well as the planning and implementation of the Company's information systems, including its customer information system, improvements to the electric load forecasting processes to support grid modernization and CLCPA goals, and various elements of pipeline safety. Discovery has concluded after 689 information requests and 42 interviews with subject matter experts and various members of Central Hudson's Board of Directors. A copy of the Draft Report was received from DPS Staff on December 28, 2022. Central Hudson's response was filed on January 20, 2023 and a meeting will be scheduled by Staff in February to discuss audit comments and recommendations.

Storm Hardening & Climate Resilience Law
On December 22, 2021, Governor Kathy Hochul Signed the Storm Hardening & Climate Resilience Bill (S4824A) into law. Part A of this law concerns Climate Vulnerability Studies and part B concerns compensation for customers experiencing widespread and prolonged outages.

Climate Vulnerability Studies
Part A requires that each utility complete a Climate Vulnerability Study evaluating its infrastructure, design specifications, and procedures to understand the utility's vulnerability to climate driven risks and file with the PSC by September 22, 2023. The law also requires utilities to file a subsequent Climate Resilience Plan within 60 days from submission of the Climate Vulnerability Study that must include 1) storm hardening and resilience measures planned for the next ten to twenty years; 2) details of how the corporation will incorporate climate change into its planning, design, operations; and emergency response, 3) details of incorporating climate change into existing processes and practices, managing climate risks and building resilience; and 4) proposed adjustments to planning and design of infrastructure in response to the increasing impacts from climate change.

On June 16, 2022, the PSC Issued its Order Initiating Proceeding Concerning Electric Utility Climate Vulnerability Studies and Plans. The proceeding was initiated to develop and consider studies, proposals, plans, rules, and procedures for implementing the provisions of the Storm Hardening & Climate Resilience Law. On July 14, 2022, the Commission issued an Order adopting the necessary definitions, processes, and procedures to implement the Storm Hardening & Climate Resilience Law. Compliance tariff leaves were filed on July 22, 2022. On August 15, 2022, the utilities jointly filed comments in response of the Order, including an ask of the Commission to move expeditiously to approve cost recovery mechanisms associated with the development and implementation of each utility's Studies and Plans.

Compensation for Widespread, Prolonged Outages
Part B of the Storm Hardening & Climate Resilience Law requires utilities to provide compensation to customers experiencing widespread and prolonged outages lasting more than 72 hours. Utilities will provide a $25/day bill credit to qualifying residential customers with additional reimbursement for spoiled food; up to a maximum of $540 with proof of loss and reimbursement of spoiled medication up to the value of the lost medication. Finally, the law requires utilities to reimburse small businesses up to $540 for spoiled food with proof of loss. The law stipulates that none of the costs incurred by the utility related to these requirements can be recoverable from ratepayers. The provisions in Part B took effect on April 21, 2022 and apply to widespread outages on both electric and natural gas service. Central Hudson has not been required to provide compensation to customers under Part B of this law through December 31, 2022.

Strategic Use of Energy Data Proceeding
On March 19, 2020, the Commission issued an Order Instituting Proceeding: Strategic Use of Energy Related Data in Case 20-M-0082 to combine the multiple proceedings where data related topics have been addressed in recent years. On February 11, 2021, the Commission issued an Order Implementing an Integrated Energy Data Resource ("IEDR") and, on April 15, 2021, issued an Order Adopting Data Access Framework ("DAF") and Establishing Further Process. The two Orders establish a statewide data repository, and the framework for the repository, which will be administered by NYSERDA and is meant to assist Energy Service Entities ("ESE") in developing Distributed Energy Resources ("DER") to help New York meet its CLCPA goals.

The Order Implementing an IEDR requires utilities to establish an IEDR Implementation Team, led by a member of the Company's senior management team. The Commission established a budget cap of $13.5 million for the Program Sponsor's efforts for Phase 1, including $12 million for procured resources and $1.5 million for the NYSERDA administrative costs as Project Sponsor. The Order directs that program costs be allocated and collected from the jurisdictional electric utilities in the same manner as the current authorized costs are being allocated and collected via the existing Bill-As-You-Go ("BAYG") agreements that NYSERDA has with each utility. Phase 1 should be completed in 24 – 30 months. Phase 2 should be completed in 30 – 36 months following completion of Phase 1. Operation of the utility's IEDR data feeds should persist for the life of the IEDR (multiple decades). The Order directs utilities to file quarterly reports on IEDR project planning and investment and NYSERDA to file an initial Implementation Plan, an updated BAYG Summary, quarterly reports and program reports on Phase 1 and Phase 2.

The Order Adopting a DAF incorporates the existing Commission established data access requirements to date including cybersecurity and privacy requirements and establishes data quality and integrity standards criterion to be met by the utility, or data custodian, for application or use case specific purposes. The Order also establishes a process that ensures the utilities will play a role with increasing customers' familiarity with appropriate data sharing options. The Joint Utility ("JU") made numerous filings in compliance with the Order including the identification of available data points that were omitted from the data sets in the Order, a proposal for an alternative method of account identification for completing ESE customer transactions, and the submission of a Consent Process Assessment and Customer Consent Engagement Plan. On September 20, 2021, the JU filed a comprehensive Data Access Implementation Plan ("DAIP") that provides a uniform method for developing statewide data access requirements. Implementation of the DAIP, when approved by the Commission, will require significant work including the procurement of a Data Ready Certification provider and development of the associated platform.

The Accelerated Renewable Energy Growth and Community Benefit Act (the "ARECB Act") and related Proceedings and Orders

On April 3, 2020, Governor Cuomo signed the ARECB Act into law in recognition that achieving the CLCPA climate protection targets requires restructuring and repurposing the State's electric transmission and distribution infrastructure. The ARECB Act has resulted in activities as discussed further below under the Renewable Energy Facility Host Community Benefit Program and Transmission Planning Proceedings subheadings.

Renewable Energy Facility Host Community Benefit Program

On February 11, 2021, the PSC issued Order Adopting a Host Community Benefit Program to provide residential electric utility customers within a Host Community an annual bill credit. The credit will be provided on electric utilities' bills for accounts of residential customers within the town or city that hosts a facility. The renewable owner will pay an annual program fee for ten years, in the amount of $500 per MW and $1,000 per MW of nameplate capacity for solar and wind facilities, respectively. Central Hudson filed its Implementation Plan for the Host Community Benefit Program for PSC consideration and approval on September 30, 2021. DPS Staff filed Host Community Benefit Annual Reporting Guidance on March 10, 2022, which includes guidance pertaining to utilities' Annual Reports. As required by the Order, applicable utilities are required to file a Host Community Benefit Annual Report in the year following the commencement of a qualifying major renewable facility.

Transmission Planning – Accelerated Renewable Energy Growth and Community Benefit

On May 14, 2020, the PSC instituted a proceeding on transmission planning pursuant to the ARECB Act to develop and consider proposals for implementing the distribution and transmission upgrades, capital expenditures and planning. The ARECB Act directs the PSC to develop and implement plans for future investments in the electric grid to ensure it will support the State's aggressive climate goals.

On September 9, 2021, the PSC issued an Order Local Transmission and Distribution Planning Process and Phase 2 Project Proposals ("September 9") that addressed the CLCPA investment criteria and Phase 2 upgrades and improves headroom calculations and visibility of headroom data to stakeholders. The Order identifies the need to better align the proposed benefit cost analysis approach with CLCPA objectives. The Order directed the JU to coordinate with NYSERDA, the NYISO and DPS

Staff on various compliance filings which were due between December 2021 and March 2022. On January 7, 2022, the JU filed a Cost Sharing and Recovery Agreement ("CSRA") and Cost Allocation Mechanism in compliance with Clauses 3 and 4 of the PSC's September 9 Order.

On January 20, 2022, the PSC issued an Order on Power Grid Study Recommendations which addressed several other findings and recommendations from the Initial Report, particularly those related to offshore wind, future onshore bulk transmission planning needs, the proposal to consider Renewable Energy Zones, and approaches to deploying advanced technologies. The Order directed the JU to file a proposed research plan to deploy advanced technologies along with a budget for the necessary work and any deployment recommendations within six months of the date of this Order, and a progress report within one year of that date. On February 1, 2022, pursuant to Clause 8 of the PSC's September 9 Order, the JU filed their Revised Headroom Calculations and on March 8, 2022, pursuant to Clause 6 of the same Order, Central Hudson along with several other utilities submitted their Petition Identifying Area of Concern Needs and Recommended Solutions. On May 12, 2022, the PSC issued Order Accepting both the CSRA and Rate Schedule 19 as compliant with its Phase 2 Order. The JU will proceed to FERC for approval of the PSC-sanctioned CSRA and Rate Schedule 19 under FPA section 205 in order to establish a cost allocation and recovery framework for Approved Local CLCPA Projects. On December 22, 2022, the JU requested an extension of Ordering Clause 5 of the Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (Order), issued September 9, 2021, which directed the Filing Parties to submit a coordinated portfolio of Phase 2 projects that meet the requisite investment criteria and benefit cost analysis by January 1, 2023. On December 29, 2022, the extension was granted until March 3, 2023.

Modifications to New York State Standard Interconnection Requirements

On March 18, 2021, the Commission issued an Order in response to the JU seeking amendments to the system upgrade cost-sharing provisions contained in the New York State Standardized Interconnection Requirements and Application process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems to modify the existing cost sharing methodology, which has been in place since January 2017. The Commission authorized temporary measures to ensure interconnection applications that would benefit from a more equitable cost-sharing methodology remain in the interconnection process until the Commission addresses the full scope of the Petition in a future Order. Central Hudson implemented the required interim cost-sharing mechanism effective as of the issuance of the Order.

Subsequently on July 16, 2021, The Commission issued an Order adopting amendments to cost-sharing mechanisms proposed by the JU, subject to modifications which include minimum subscription thresholds and a "free-rider" protection mechanism. The Order directed the JU to complete the following: consult with other participants in the Interconnection Policy Working Group ("IPWG") and file relevant revisions to the Standardized Interconnection Requirements (including addressing the "free-rider" concern); consult with DPS Staff and the IPWG to identify and propose relevant adjustments to hosting capacity maps; and file a proposal for a reimbursement mechanism. In accordance with the Order and subsequently approved extension by the Commission, the JU filed its proposed hosting map capacity adjustments and proposed cost reimbursement mechanism on October 28, 2021. On April 14, 2022 the Order adopting amendments to the cost sharing mechanisms was approved by the Commission. All new projects submitted after April 14th will fall under Cost Sharing 2.0. Central Hudson filed their first report on November 30, 2022. There are no cost sharing projects at this time.

Value of Distributed Energy Resources Proceeding – Value of "D"

In December 2015, the Commission instituted Case 15-E-0751, "In the Matter of the Value of Distributed Energy Resources ("VDER")" to propose valuation methods for DER. Through this proceeding, the Commission has taken a number of actions including the sunsetting of statutory net energy metering ("NEM") under Public Service Law and the implementation of the Value Stack as the preferred compensation methodology for energy injected into the grid from DER technologies. The

Commission has also established a number of transitional mechanisms to moderate the impact of the changeover from statutory NEM to the Value Stack, including the limited extension of NEM with slightly more restrictive provisions than statutory NEM. On August 13, 2021, the Commission issued an Order Adopting Net Metering Successor Tariff Filings with Modifications continuing the extension of limited NEM for certain projects interconnected on and after January 1, 2022, and requiring certain projects interconnected on and after January 1, 2022, regardless of compensation method (NEM or Value Stack) to be subject to a Monthly Customer Benefit Contribution eliminating the ability of these projects to avoid funding of public benefit programs. Most recently, the Commission issued an order on September 15, 2022 seeking to establish CDG billing metrics to track and evaluate utilities' performance in CDG billing. Several stakeholder sessions will be held to inform Staff's anticipated proposal for Commission consideration.

In addition to compensation policy, the Commission has explored rate design issues through the VDER proceeding including focus on standby and buyback rates. On November 25, 2020, the DPS Staff issued a Whitepaper on Allocated Cost of Service ("ACOS") Methods Used to Develop Standby and Buyback Service Rates. The whitepaper recommended a standardized ACOS study methodology and rate design for standby rates and buyback service rates for stand-alone energy storage systems. The central issue in this proceeding is the allocation of costs between the categories comprising the contract demand charge and the as-used demand charge, such that standby rates truly reflect cost causation. The JU and other parties have presented various methods of cost allocation through public filings, technical conference discussions, and written comments. In March 2022 the Commission issued an order ruling on the Staff Whitepaper and requiring another set of draft filings by the utilities which were filed in July 2022 and contained updated ACOS studies, draft tariff revisions and proposed rates. The Joint Utilities are currently working on developing mass market bill impacts of the proposed rates filed in July 2022. A proposed approach to the bill impact analysis was filed in compliance with the March 2022 order on January 3, 2023 and a subsequent stakeholder conference is anticipated to discuss the utilities' planned approach. Central Hudson is awaiting an Order in this proceeding or further Commission action.

Community Distributed Generation ("CDG")

In November 2021, the PSC issued Order Identifying Further Procedural Steps Regarding the Development of Opt-Out Community Distributed Generation. Subsequently on March 29, 2022, DPS Staff filed its Whitepaper on proposed opt-out CDG program operation, oversight, and enforcement rules for future PSC consideration. CCA provides municipalities with legal authority to act as an aggregator and broker for the sale of energy and other services to residents via an opt-out enrollment process. This Whitepaper outlines the implementation of a statewide CDG program on an opt-out basis under the CCA model and offers recommendations in four categories: Opt-Out CDG Program Structure, Opt-Out CDG Program Rules, Data Access and CDG Billing and Crediting, and Opt-Out CDG Compliance and Enforcement. In accordance with the Commission's April 11, 2022, Notice Seeking Comments, on June 6, 2022, the Joint Utilities filed comments on the Opt-Out CDG Whitepaper noting overall support for Opt-Out CDG but outlining the need for refinements and technical workshops.

On September 15, 2022, the Commission issued an Order establishing a process intended to address and resolve ongoing CDG billing issues, improve the industry's visibility into the utilities' transition to an automated Net-Crediting billing process, and incentivize more accurate and timely utility performance in billing for CDG. An initial stakeholder conference focused on developing utility CDG crediting and billing performance metrics and a negative revenue adjustment mechanism was held on November 9, 2022. Any proposals for utility CDG billing metrics, including negative revenue adjustments, and reporting, will be brought before the Commission for consideration prior to implementation or adoption.

Additionally, as directed by the September 15, 2022 Order, Central Hudson filed on October 17, 2022, Implementation Plans detailing the progress toward automation of crediting and billing of CDG including: 1) the current billing system constraints preventing full CDG billing automation; (2) the billing system changes necessary to effectuate automated CDG billing; and (3) the steps and timeline to achieve full automation of CDG billing. Further, updates to the Implementation Plans will be required to be made quarterly until automation efforts are completed.

Clean Energy Standard ("CES") / CEF

In June 2015, Governor Cuomo announced New York State's 2015 State Energy Plan as a comprehensive roadmap to build a clean, resilient, and affordable energy system for New York State. Governor Cuomo directed the PSC to develop a CES through GHG emission reduction targets through an enforceable mandate. Administered by NYSERDA, the CES is a framework for the direct procurement of qualifying generation through two mechanisms: Renewable Energy Credits ("RECs") including Offshore Wind Renewable Energy Credits, and Zero-Emissions Credits. Additionally, Alternative Compliance Payments were established as a penalty mechanism on load-service entities which did not meet their Tier 1 REC obligations in a given year.

On November 30, 2021, NYSERDA filed its Petition Regarding Agreements for Procurement of Tier 4 RECs. The petition submitted NYSERDAs' contracts for Clean Path New York and Champlain Hudson Power Express projects for PSC review and approval. These projects will develop electric transmission infrastructure that reduces congestion and increases availability of renewable energy in New York City. The total cost for the two projects is approximately $24 billion, with estimated benefits from avoidable expenditures and environmental impacts estimated between $27 to $31 billion. The PSC approved this petition in its Order Approving Contracts for the Purchase of Tier 4 Renewable Energy Certificates on April 14, 2022.

On July 29, 2022, NYSERDA filed its Petition Regarding Proposed Year 2023 Clean Energy Standard Funding and Reconciliation of Year 2021 Administrative Costs. Specifically, NYSERDA is proposing an administrative budget of $38.8 million for the CES 2023 Compliance Year, which would include staff direct and indirect salaries, fringe benefits, and other direct program operating costs and general administrative expenses. This represents an increase of approximately 29% from the 2022 budget of $30.2M. On December 15, 2022 the PSC approved NYSERDA's proposed administrative budget with modifications, reducing its proposed budget by $5.4 million in areas related to staffing and technical support. On November 9, 2022 NYSERDA filed a petition with the PSC to modify the CES to transition from a defined percentage obligation to a load share obligation for load serving entities. Under the current Tier 1 approach, Load Servicing Entities ("LSEs") must meet their compliance obligation, which is represented as a pre-determined and ascending percentage of the load they serve, by procuring Tier 1 RECs from NYSERDA or other sources, or, in the alternative, by making Alternative Compliance Payments ("ACPs"). Under the new approach proposed in this petition, LSEs would simply be obligated to procure all Tier 1 RECs made available by NYSERDA, after the completion of voluntary sales, in a proportion equivalent to their share of the State load or load share. Without a pre-determined compliance obligation percentage, there would no longer be a need for ACPs, nor would there be an incentive for LSEs to purchase RECs outside of those purchased by NYSERDA.

CEF Backstop

In 2016, the Commission determined that NYSERDA may need a guarantor, i.e., a backstop to address the financial risk associated with meeting renewable energy credit procurement obligations to generators under the CES and that electric utilities are best situated to serve that role, subject to recovery from customers. Subsequently, the Commission expanded the backstop concept to include zero emission credits and offshore wind renewable energy credits, the CES Build-Ready Program, and all CES programs. On July 1, 2021, NYSERDA filed its Proposed Clean Energy Standard Financial Backstop Collections Process with the Commission. In comments filed on September 27, 2021, the JU urge the Commission to reject NYSERDA's backstop proposal because it would trigger additional and potentially significant collections from customers based on a summary of undefined reports and forecasts without public review or Commission action in contradiction to the Commission's direction for transparency. Instead, the JU urge the Commission to adopt their proposal based on a simpler, transparent, and public review of cash working capital that should prevent unnecessary increases in customer bills while providing NYSERDA with sufficient funds to meet its CES procurement obligations and cash needs for the Build-Ready Program.

ZECs

On September 20, 2019, the Commission issued Order Approving Zero Emissions Credit Implementation Plan which adopts a "pay-as-you-go" model to address the program design issue that payment obligations were not responsive to changes in LSEs' loads. Under the "pay-as-you-go" model, changes in LSE load can be automatically adjusted, eliminating the need for LSEs to petition the Commission for relief. NYSERDA is required to provide each affected LSE with a revised agreement. Central Hudson provided NYSERDA with an executed copy of the Agreement for the Sale of Zero-Emission Energy Certificates on January 2, 2020.

CES Administration Budget

On December 16, 2021, the Commission approved NYSERDA's 2022 CES administration budget of $30.2 million as proposed by NYSERDA. This budget will fund program salaries and overhead, New York State cost recovery expense, technical support, and system development. NYSERDA is authorized to fund these expenditures through a combination of surplus funds received in previous years, including bid fees, Alternative Compliance Payments and interest income. For the ZEC program, NYSERDA will continue to fund its administration through a ZEC adder.

Energy Efficiency (New Efficiency: New York) Proceeding

In September 2022, the Commission issued Order Initiating the New Efficiency: New York Interim Review and CEF Review. The review is intended to provide an opportunity to assess progress to date and consider modifications that will improve the management of the portfolios, increase the effectiveness of the programs, and ensure alignment with evolving state policies. Subsequently in December 2022, DPS Staff issued its Energy Efficiency and Building Electrification Report. The report details historical performance across all programs and portfolios, identifies areas of success or potential concern, and contemplates necessary policy adjustments. The report contains 42 specific questions that DPS Staff puts forth for stakeholder comments.

Climate Leadership and Community Protection Act

In June 2019, the CLCPA was passed by the New York State Senate and the New York State Assembly. The CLCPA includes renewable energy and emission reduction targets for New York State, which are the most aggressive in the nation. The CLCPA defines targets for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. It requires the PSC to establish a program to require all load serving entities to together procure 6,000 MW of solar energy by 2025, 3,000 MW of energy storage by 2030 and 9,000 MW of offshore wind energy by 2035. The CLCPA also requires New York State to cut GHG emissions 40% (from 1990 baseline levels) by 2030 and 85% by 2050 and to achieve net-zero carbon emissions by 2050. The remaining 15% of emissions needed to achieve net-zero are to be offset or captured via the use of carbon capture and sequestration technology and expansion of natural carbon sinks through planting trees and wetlands restoration. These emissions offset projects may be established by the Department of Environmental Conservation as an alternative compliance mechanism for sources subject to the emissions limits. The bill requires the PSC to issue a comprehensive review of the program by July 1, 2024.

The PSC will have the authority to temporarily suspend or modify the obligations under the program provided a hearing finds that the program impedes the provision of safe and reliable electric service, impairs existing obligations or significantly increases arrears or service disconnections determined to be related to the program.

On May 12, 2022, the PSC issued an Order on Implementation of the CLCPA under Case 22-M-0149. This Order initiates a proceeding to track compliance and develop provisions of the CLCPA, including minimum percentages of benefits to be distributed to disadvantaged communities. Specific requirements are (i) costs of large-scale clean energy projects will be distributed statewide on a load-ratio share basis, (ii) utilities will work with the Department of Public Service to develop a proposal by December 2, 2022 for annual GHG Emissions Inventory Reports, (iii) utilities will develop a proposal by March 31, 2023 for a GHG Emissions Reduction Pathways Study to achieve carbon reductions from use of delivered gas, and (iv) rates proceeding will begin for new electric-vehicle charging. Coincident with the Implementation Order, the PSC also issued a request for public comments regarding utility ownership of distributed energy resources and large-scale renewables. Although this has been discussed in the past, this Order is allowing additional consideration for the opportunity of utility owned DER and LSRs.

Thermal Network Pilots

On July 5, 2022, the Utility Thermal Energy Networks and Jobs Act ("Act") was signed into law by Governor Kathy Hochul. The Act requires utilities to submit proposals for up to five thermal energy pilots and requires the PSC to promulgate rules and regulations related to thermal energy networks. The Act includes provisions requiring that such projects be located in disadvantaged communities and that the operation of the projects be staffed with union labor and include apprenticeship and pre-apprenticeship programs. On September 15, 2022, the PSC issued an Order on Developing Thermal Energy Networks Pursuant to the Utility Thermal Energy Network and Jobs Act under Case 22-M-0429. This Order required that utilities in New York State, including Central Hudson, submit proposals for pilot projects to install anywhere from one to five thermal energy networks as demonstrations for how the building sector can be transitioned from using fossil fuels for space and water heating. In accordance with the Order, Central Hudson filed its Thermal Energy Network Pilot Plan on October 7, 2022 and subsequently filed the Thermal Energy Network File Plan Update on January 9, 2023.

Electric Vehicles

On December 31, 2021, Governor Kathy Hochul signed bill A3876/S3929 into law, requiring utilities to propose alternative non-demand based commercial electric vehicle charging tariffs. Subsequently on March 18, 2022, Governor Kathy Hochul signed bill A8797/S7836 into law which amended the prior law by expanding the scope of the utilities' proposal to other potential operating cost relief mechanisms. The amended law also requires the PSC to evaluate the relative costs of the proposed solutions and issue an Order modifying or proposing those solutions by March 18, 2023. On July 14, 2022, the PSC issued the Order Approving Managed Charging Programs with Modifications, establishing utility administered programs which are designed to encourage vehicle charging during off-peak times. Subsequently, DPS Staff convened a stakeholder session to examine this topic. Central Hudson filed its Managed Charging Program Implementation Plan on September 26, 2022.

On September 26, 2022, DPS Staff issued the Whitepaper Regarding Alternatives to the Traditional Demand Charge for Commercial Customer Electric Vehicle Charging. The Whitepaper recommends a combination of solutions including a Commercial Managed Charging Program and an EV Phase-in Rate. On December 5, 2022 the Joint Utilities filed comments in response to the Whitepaper, recommending modifications to its proposals, differentiated based on the needs of upstate and downstate utilities.

Additionally, DPS Staff commenced the Electric Vehicle Supply Equipment Make-Ready program midpoint review on August 30, 2022. Subsequently on October 3, 2022, the Joint Utilities filed comments related to the midpoint review, which recommended modifications to promote target achievement aligned with policy goals that will have a significant impact on the success of the program. The recommendations included increasing incentives and associated budgets to align incentives with market needs in light of the Commission's public policy objectives, expanding eligibility rules for equipment (including chargers) and supporting technologies, and redesigning/expanding the Medium/Heavy Duty Pilot to remove current barriers to participation.

Energy Storage

In December 2018, the Public Service Commission established a statewide energy storage goal of up to 3,000 MW by 2030 and laid out its policy on deployment in its Order Establishing Energy Storage Goal and Deployment Policy. After two rounds of competitive procurements targeting a total of 350 MW of energy storage resources by the end of 2022, the Joint Utilities have generally not yet been able to contract with projects that are able to meet the Commission's goals. On November 30, 2022, the Joint Utilities filed a Petition to Modify the Energy Storage Order to Improve Procurement Results. Specifically, the Joint Utilities requested (1) an extension of the in-service date for storage resources from December 31, 2025 to no later than December 31, 2028 and (2) an extension of the maximum dispatch rights contract duration from the current "up to ten (10) years" to "up to fifteen (15) years.". On December 28, 2022, NYSERDA and the NYSDPS published a new framework for the State to achieve a nation-leading six gigawatts of energy storage by 2030, which represents at least 20 percent of the peak electricity load of New York State. The roadmap proposes a comprehensive set of recommendations to expand New York's energy storage programs to cost-effectively unlock the rapid growth of renewable energy across the state and bolster grid reliability and customer resilience. The roadmap requires electric utilities to study the potential of high-value energy storage projects towards providing cost-effective transmission and distribution services not currently available through existing markets.

Gas Planning Proceeding

On February 12, 2021, Staff filed the Gas System Planning Process Proposal which offers a modernized gas planning process for the gas distribution utilities in New York State and a Staff Moratorium Proposal that identifies procedures and criteria for managing moratoria on new attachments to the gas distribution systems.

On May 12, 2022, the PSC issued two orders in the Gas Planning Proceeding: Order Adopting Gas System Planning Process ("Planning Process Order") and Order Adopting Moratorium Management Procedures ("Moratorium Order"). Through the Planning Process Order, the PSC adopted modernized long-term natural gas planning procedures to ensure that the State, customers, stakeholders, and all other interested entities have the opportunity to understand and engage in the future of natural gas infrastructure in the State. The Order also directed Staff to establish an Avoided Cost of Gas Working Group to provide recommendations for improving calculations used in Benefit-Cost analyses. Through the Moratorium Order, the PSC adopted new rules that set forth the process for initiating, operating, and lifting a natural gas moratorium, and covers issues including the metrics used to identify supply shortfall, communications, a Customer Bill of Rights, training materials and outreach, and information on low- and moderate-income customer and disadvantaged community impacts.

In compliance with the Gas Planning Process Order, on August 10, 2022, the Company and the Joint Utilities made several filings to address proposed Non-Pipes Alternative ("NPA") screening and suitability criteria, proposed NPA incentive mechanism, proposed NPA cost recovery procedures and filed a report on the costs of the 100-foot rule. Draft tariffs were filed with the criteria that would necessitate the calling of a gas moratorium in compliance with the Moratorium Order. The Company filed a Moratorium Communications Plan on December 27, 2022.

Pipeline and Hazardous Materials Safety Administration

As a result of rulemaking Case PHMSA-2011-0023, the PHMSA, which is an agency of the United States Department of Transportation, has issued the first of the three-part Safety of Gas Transmission Pipeline Regulation updates. This first part includes Maximum Allowable Operating Pressure ("MAOP") Reconfirmation, Expansion of Assessment Requirements (creation of Moderate Consequence Areas) and Other Related Amendments. The effective date is July 1, 2020, with a required plan in place by

July 1, 2021, to ensure MAOP reconfirmation is 50% completed by 2028 and 100% completed by 2035. The second part is not final but is expected to address extensive updates to response and repair criteria for integrity assessment and to expand cathodic requirements. PHMSA is additionally introducing legislation changes to current regulations to mitigate ruptures and shorten pipeline segment isolation times on all newly constructed or fully replaced gas transmission lines. The third part of the Transmission Super Rule is not applicable to the Company since it deals only with gas gathering lines. Central Hudson currently estimates that the rule will impact up to 75 miles of its transmission pipelines. NY State adopted the federal code changes into state code within Case 20-G-0560. Recovery and deferral of costs associated with Safety of Gas Transmission Final Rules were addressed within the 2021 Rate Order. The second part of the Mega-Rule was issued in August 2022 with extensive updates to Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments. These updates are currently anticipated to require some procedural changes but will have only minor impacts to Central Hudson's natural gas business operations. The third part of the Transmission Mega-Rule is not applicable to the Company as it deals only with gas gathering lines. In April 2022, PHMSA issued changes to current regulations to mitigate ruptures and shorten pipeline segment isolation times on all newly constructed or fully replaced gas transmission lines. Central Hudson has no plans to significantly expand or replace any large sections of its gas transmission lines in the foreseeable future, therefore, this rulemaking is expected to have only minor impacts to Central Hudson's natural gas business operations.

FERC Notice of Pending Jurisdictional Inquiry

On June 24, 2019, Central Hudson received a notification and initial information requests from FERC for a jurisdictional inquiry regarding its hydroelectric projects at Sturgeon Pool and Dashville. The FERC also issued a Notice of Pending Jurisdictional Inquiry with any comments, motions to intervene and protests to be filed by August 8, 2019. These projects were determined to be non-jurisdictional in previous investigations based on the conclusion that the Wallkill River is not navigable as defined within the Federal Power Act at the location of the projects. In response to a request by the US Department of the Interior's Fish and Wildlife Service, the FERC will investigate the jurisdictional status of these projects. Central Hudson submitted responses to the information requests on August 8, 2019. On October 30, 2020, Central Hudson submitted to FERC additional information on docket UL19-1 so that FERC may decide the jurisdictional question on the facts and the law. No other process has been scheduled by FERC at this time. On November 17, 2021, Fish and Wildlife asked FERC to expedite its process to decide the case. FERC has not placed the case on its agenda and we cannot predict when a decision will occur.

FORWARD-LOOKING STATEMENTS

Statements included in this Annual Financial Report, which are not historical in nature, are intended to be "forward-looking statements." Forward-looking statements may be identified by words such as "anticipate(s)," "intend(s)," "estimate(s)," "believe(s)," "project(s)," "expect(s)," "plan(s)," "assume(s)," "seek(s)," and other similar words and expressions. CH Energy Group is subject to risks and uncertainties that could cause actual results to differ materially from those indicated in the forward-looking statements. The risks and uncertainties may include, but are not limited to, deviations from normal seasonal temperatures and storm activity, changes in energy and commodity prices, availability of energy supplies, a cyber-attack, changes in interest rates, poor operating performance, legislative, tax and regulatory developments, the outcome of litigations, the COVID-19 pandemic, and the resolution of current and future environmental and economic issues. Additional information concerning risks and uncertainties may be found in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of CH Energy Group's Annual Financial Reports. These reports are available in the Financial Information section of the website of CH Energy Group, at www.CHEnergyGroup.com. CH Energy Group undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events, or otherwise.

ITC HOLDINGS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31,	
(In millions of USD, except share data)	**2022**	**2021**
ASSETS		
Current assets		
Cash and cash equivalents	$ 4	$ 5
Accounts receivable	139	128
Inventory	55	45
Regulatory assets	12	21
Prepaid and other current assets	19	18
Total current assets	229	217
Property, plant and equipment (net of accumulated depreciation and amortization of $2,382 and $2,199, respectively)	10,637	9,961
Other assets		
Goodwill	950	950
Regulatory assets	181	190
Other assets	134	127
Total other assets	1,265	1,267
TOTAL ASSETS	$ 12,131	$ 11,445
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable	$ 112	$ 127
Accrued compensation	59	72
Accrued interest	69	56
Accrued taxes	72	64
Regulatory liabilities	22	14
Refundable deposits and advances for construction	26	44
Debt maturing within one year	384	654
Other current liabilities	15	16
Total current liabilities	759	1,047
Accrued pension and postretirement liabilities	41	52
Deferred income taxes	1,303	1,161
Regulatory liabilities	676	619
Refundable deposits	29	28
Other liabilities	44	55
Long-term debt	6,607	6,009
Commitments and contingent liabilities (Notes 5 and 16)		
TOTAL LIABILITIES	9,459	8,971
STOCKHOLDER'S EQUITY		
Common stock, without par value, 235,000,000 shares authorized, 224,203,112 shares issued and outstanding at December 31, 2022 and 2021	892	892
Retained earnings	1,753	1,584
Accumulated other comprehensive income (loss)	27	(2)
Total stockholder's equity	2,672	2,474
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 12,131	$ 11,445

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(In millions of USD)	2022	2021	2020
OPERATING REVENUES			
Transmission and other services	$ 1,476	$ 1,358	$ 1,290
Formula Rate true-up	(10)	(9)	8
Total operating revenue	1,466	1,349	1,298
OPERATING EXPENSES			
Operation and maintenance	107	108	87
General and administrative	105	128	115
Depreciation and amortization	295	232	219
Taxes other than income taxes	139	133	124
Other operating (income) and expense, net	(1)	(1)	—
Total operating expenses	645	600	545
OPERATING INCOME	821	749	753
OTHER EXPENSES (INCOME)			
Interest expense, net	269	251	240
Allowance for equity funds used during construction	(37)	(30)	(27)
Other expenses (income), net	1	(5)	(3)
Total other expenses (income)	233	216	210
INCOME BEFORE INCOME TAXES	588	533	543
INCOME TAX PROVISION	146	127	136
NET INCOME	442	406	407
OTHER COMPREHENSIVE INCOME (LOSS)			
Derivative instruments, net of tax (Note 12)	29	6	(15)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	29	6	(15)
TOTAL COMPREHENSIVE INCOME	$ 471	$ 412	$ 392

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions of USD)	Year Ended December 31, 2022	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 442	$ 406	$ 407
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	295	232	219
Recognition, refund and collection of revenue accruals and deferrals — including accrued interest	18	52	(47)
Deferred income tax expense	131	127	138
Allowance for equity funds used during construction	(37)	(30)	(27)
Share-based compensation	11	34	25
Other	57	6	4
Changes in assets and liabilities, exclusive of changes shown separately:			
Accounts receivable	(8)	(18)	—
Accounts payable	10	(3)	4
Accrued interest	12	1	7
Accrued compensation	(15)	(3)	(14)
Accrued taxes	7	3	(3)
Net refund settlements and adjustments related to return on equity complaints	—	(5)	(65)
Other current and non-current assets and liabilities, net	(31)	(17)	(16)
Net cash provided by operating activities	892	785	632
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(933)	(834)	(885)
Other	8	10	7
Net cash used in investing activities	(925)	(824)	(878)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	975	75	1,030
Borrowings under revolving credit agreements	1,119	1,175	1,495
Borrowings under term loan credit agreements	—	—	275
Net (repayment) issuance of commercial paper	(21)	88	(133)
Repayment of long-term debt	(500)	—	(35)
Repayments of revolving credit agreements	(1,240)	(1,044)	(1,596)
Repayments of term loan credit agreements	—	—	(475)
Dividends to ITC Investment Holdings	(273)	(232)	(330)
Refundable deposits from generators for transmission network upgrades	1	18	60
Repayment of refundable deposits from generators for transmission network upgrades	(19)	(39)	(10)
Other	(10)	(1)	(35)
Net cash provided by financing activities	32	40	246
NET (DECREASE) INCREASE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	(1)	1	—
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — Beginning of period	7	6	6
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — End of period	$ 6	$ 7	$ 6

See notes to consolidated financial statements.