Strength in Connections


FORTIS

2020 ANNUAL REPORT

One Strong Connection Throughout North America

PURPOSE

Delivering a cleaner energy future

VALUES

We never compromise on **safety**

Nothing matters more to us than protecting the health and safety of our employees, customers and contractors. Our pursuit of safety is relentless.

We value our **people**

Our employees are dedicated. We take pride in working hard and doing the right thing. We seek and develop diverse talent and offer an inclusive work environment.

We keep it **local**

We believe in local decision-making. Our teams understand the communities we serve. Our companies operate independently, but together as a family of companies we do more than any of us could do alone.

We act with **courage** and **integrity**

We make the right decisions for the long term, even when it's a tough call. We keep our promises and hold ourselves to the highest ethical standards.

We are **community** champions

We make our communities stronger by nurturing local partnerships and giving back to the places we proudly serve.

We aim for **excellence** every day

We are energy delivery experts, dedicated to service, performance and growth. We respect the environment and drive innovation to provide energy solutions for our customers.

FORTIS Quick Facts

3.3 million customers

9,000 employees strong

Corporate-wide **emissions reduction target of 75% by 2035** compared to 2019 levels

47 consecutive years of dividend payment increases

Fortis delivered its **best safety performance** ever in 2020

$55 billion in total assets

10 utilities in Canada, the U.S. and the Caribbean

60% of Fortis utilities have either a **female CEO or Board Chair**

TSX/NYSE: FTS

Community investment **of more than $15 million in 2020**

Unless otherwise specified, all financial information is referenced in Canadian dollars and all numbers are as at December 31, 2020.

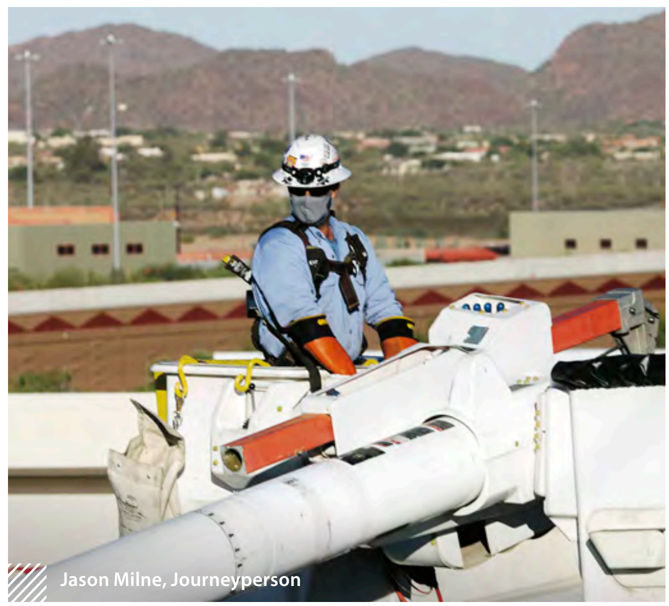
REPORT TO SHAREHOLDERS

Connected to Our People and Communities

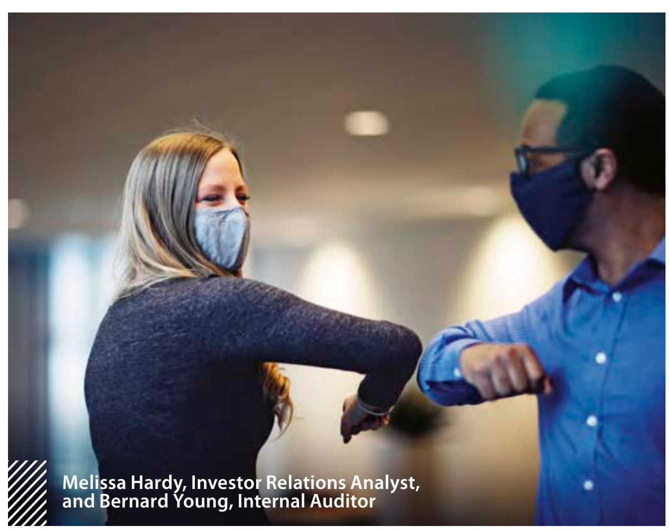
Leading with Strength

We are proud of what we have accomplished as a family of companies in 2020. Our accomplishments were many despite the new and unusual ways the pandemic required us to approach our work.

The COVID-19 response at Fortis utilities is grounded in our commitment to employee safety and supporting our local communities. Approximately half of our 9,000 employees quickly and efficiently transitioned to working from home while our teams working in field operations adapted to work safely to keep the lights on and the natural gas flowing for our 3.3 million customers.


Jason Milne, Journeyperson

Throughout the pandemic we are seeing our resilience and values shine bright and, while we are physically distant, in many ways we have never been more connected.


Melissa Hardy, Investor Relations Analyst, and Bernard Young, Internal Auditor

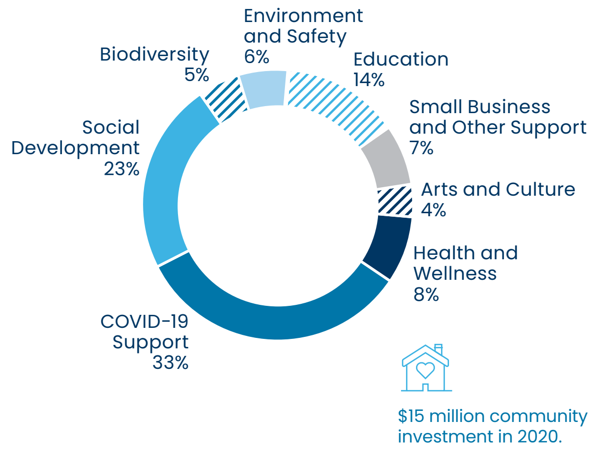
On behalf of our Board, we extend our sincerest thanks and gratitude to our employees and their families for the commitment and care they have consistently demonstrated.

Rodel Nacion, Customer Service Leader

Our local operating model remains at the forefront, with our teams maintaining close connections to their customers and communities throughout the pandemic. This facilitated our timely, decisive and agile response to COVID-19. Our management teams stay focused on what matters most to their employees, customers and local communities, while tapping into the vast network of expertise across the Fortis group to collaborate and create innovative ways to deliver excellent customer service.

We understand the pandemic has been very difficult for so many of our customers. Our utilities have been supporting customers by suspending service disconnects, waiving late fees and offering flexible payment options. The Fortis group of companies also invested more than $15 million in our communities in 2020. This amount includes approximately $5 million specifically for COVID-19 community support, such as food banks, mental health agencies and organizations providing personal protective equipment for essential workers.

2020 COMMUNITY INVESTMENT AREAS



The Fortis Community Matters Project

In May 2020, Fortis donated $500,000 to 20 non-profit organizations to provide immediate financial support to frontline COVID-19 community response efforts in the headquarter province of Newfoundland and Labrador.

"Thank you, thank you, we are truly humbled. From all those children and families who will have food, because of Fortis, what an impact you are making."

– Fortis Community Matters Project recipient


Scott Hutton, Lead Powerline Technician Construction

Record Safety Results

Safety of our employees is crucial and in 2020 Fortis delivered the best safety performance in its history.

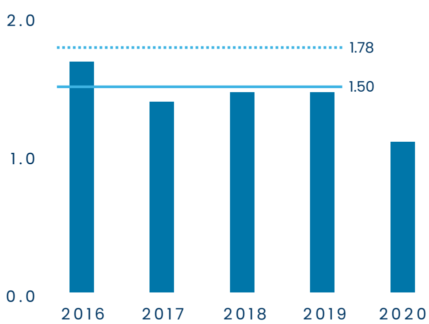
We track our all-injury frequency rate ("AIFR") as an indicator of safety performance, which represents the number of injuries for every 200,000 hours worked.

Our AIFR for 2020 was 1.09, an improvement of approximately 25% in comparison to the prior three-year average. Achieving these results in such a challenging year is a testament to our focus and commitment to safety, especially since historically we perform better than the industry average.

Reliable Service to Customers

Fortis consistently remains in the top quartile relative to our industry peers in terms of reliable energy delivery. We track electricity reliability using the average hours of interruption per customer. In 2020 our average outage duration was 1.9 hours, outperforming both Canadian and U.S. industry average outage durations.

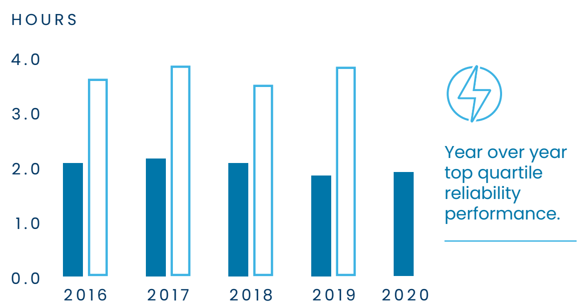
ALL-INJURY FREQUENCY RATE[1]



- Fortis
- USA Bureau of Labor Statistics (2016-2019 Average)
- Canadian Electricity Association (2016-2019 Average)

(1) Injuries per 200,000 hours worked.

ELECTRICITY CUSTOMER AVERAGE OUTAGE DURATION[2]



- Fortis
- Canadian Electricity Association and U.S. Energy Information Administration Average

(2) Based on weighted average of Fortis' customer count in each jurisdiction.

Strong Financial Performance

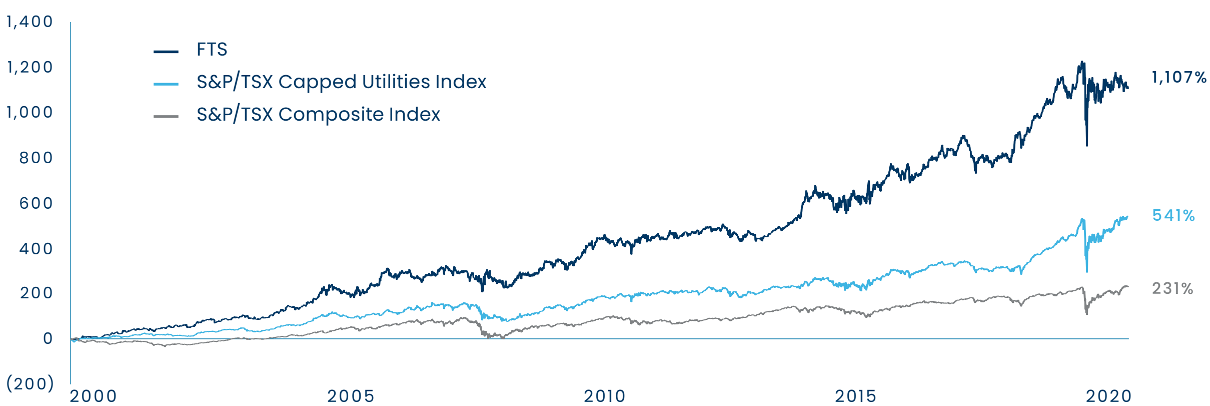
In 2020 net earnings attributable to common equity shareholders were $1,209 million, or $2.60 per common share, compared to $1,655 million, or $3.79 per common share, for 2019. The change in net earnings reflects significant one-time items including a $484 million gain on the disposition of the Waneta Expansion and a $56 million year over year impact associated with a U.S. federal regulatory decision. Notwithstanding these one-time items, earnings grew by $94 million in 2020. We achieved adjusted net earnings of $1,195 million, or $2.57 per common share, in 2020 compared to $1,115 million, or $2.55 per common share, in 2019.

Fortis is well positioned in terms of liquidity due in part to a $1.2 billion common equity offering and the $1.0 billion sale of the Waneta Expansion hydroelectric generating facility in 2019. Together, these actions generated a significant portion of the equity funding required to execute our five-year capital plan and significantly strengthened our liquidity. At the end of 2020 total consolidated credit facilities were $5.6 billion with $4.3 billion unutilized.

Over a 20-year period, Fortis has delivered a total shareholder return of 1,107%.

Over the same 20-year period, the S&P/TSX Composite and S&P/TSX Capped Utilities indices delivered total returns of 231% and 541%, respectively.

SUPERIOR 20-YEAR TOTAL SHAREHOLDER RETURN



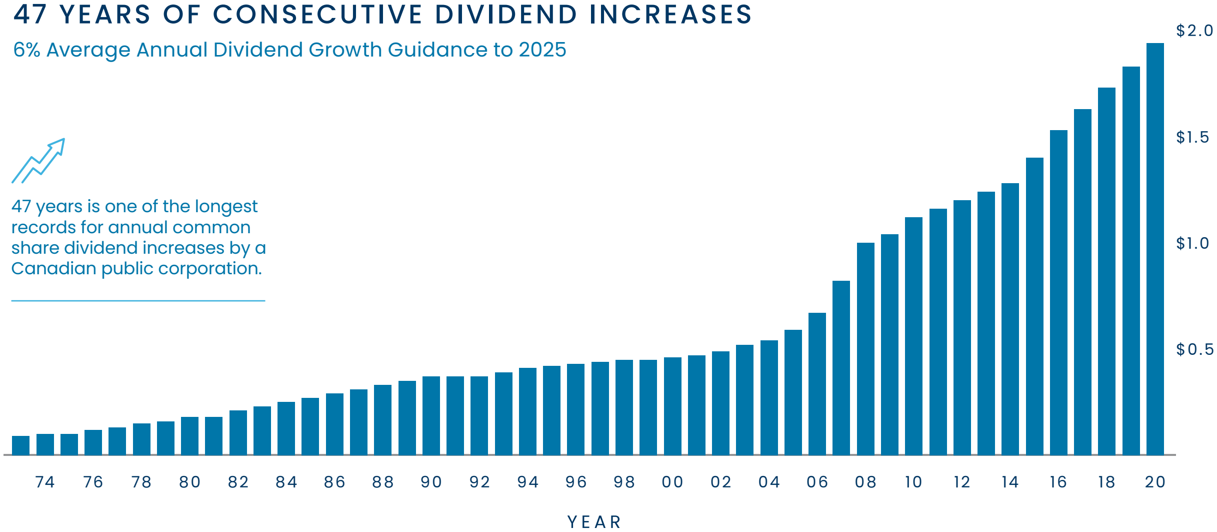
Note: Cumulative 20-year total shareholder return as at December 31, 2020.

In aggregate, we paid dividends per common share of $1.94 in 2020, an increase of 6% compared to 2019. This increase marked 47 consecutive years of dividend increases, one of the longest records for annual common share dividend increases by a Canadian public corporation.

With confidence in the growth profile of our low-risk, geographically diversified group of utilities, we extended our average annual dividend growth guidance of 6% to 2025.

47 YEARS OF CONSECUTIVE DIVIDEND INCREASES

6% Average Annual Dividend Growth Guidance to 2025



Pete Cox, Fleet Services

Kealey Martin, Director, Sustainability, and Andy Morgans, Sustainability Analyst

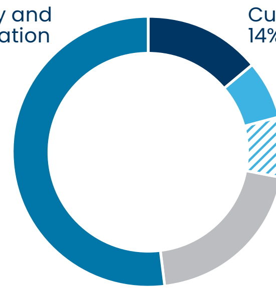
Alison Fitzgerald, Manager, Financial Reporting

Record Capital Investments of $4.2 billion

We deployed record capital expenditures of $4.2 billion in 2020, resulting in annual rate base growth of 8.2%.

Our utilities executed our largest capital plan ever while also managing through the pandemic and delivering record safety performance. Several Fortis utilities also experienced significant storm events in 2020. Central Hudson, FortisTCI, ITC Holdings Corp., Maritime Electric and Newfoundland Power experienced extreme weather events that required a rapid response to restore service to customers. This performance speaks to the operational expertise and strength of the leadership teams across Fortis.

2020 $4.2 BILLION CAPITAL PLAN



With 93% of our assets associated with the delivery of electricity and natural gas, one of the best ways we can support decarbonization is to ensure our infrastructure can deliver cleaner energy to customers.

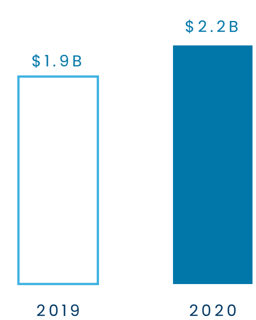
A Capital Plan Focused on Resiliency, Modernization and Delivery of Cleaner Energy

The $4.2 billion 2020 capital plan included $2.2 billion spent on resiliency and modernization and $0.9 billion on projects that reduce emissions, water usage or increase customer energy efficiency. Resiliency, modernization and cleaner energy capital investments increased by approximately 20% in comparison to 2019.

Five-Year Capital Plan

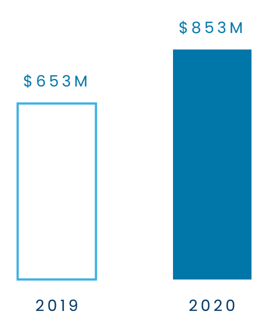
Our $19.6 billion five-year capital plan for the period 2021 to 2025 reflects a $0.8 billion increase over the prior plan. Capital investments are expected to average approximately $4 billion annually over the five-year period, increasing rate base by approximately $10 billion to $40.3 billion and supporting a compound annual growth in rate base of approximately 6%. With virtually all regulated investments consisting of a diverse mix of highly executable and low-risk projects, we are focused on delivering safe, reliable, cleaner and cost-effective service to customers.

RESILIENCY AND MODERNIZATION CAPITAL



Spending on resiliency and modernization increased by $0.3 billion in 2020.

CLEANER ENERGY CAPITAL



Cleaner energy spending increased by $200 million in 2020.

Delivering a Cleaner Energy Future

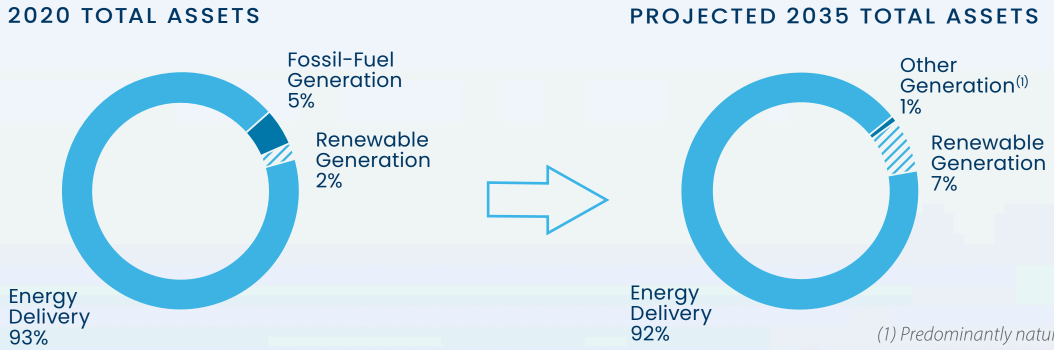
In 2020 we increased our focus on supporting a low-carbon future with an aggressive corporate-wide target to reduce carbon emissions by 75% by 2035 from a 2019 base year. This carbon reduction target builds on our existing low-emissions profile and substantially reduces carbon emissions over a relatively short timeframe. The pace of our planned emissions reduction is well below the two-degree Celsius pathway and is aligned with the goals of the Paris Agreement.

To achieve this target, we expect to add 2,400 MW of wind and solar power systems and approximately 1,400 MW of energy storage systems at Tucson Electric Power ("TEP") by 2035. Although generating electricity is only a small part of our business, the renewable generation capacity planned at TEP alone will lead to an almost five-fold increase in renewable generation capacity at Fortis. Clean energy initiatives at our other utilities will also contribute to achieving this goal.

An aggressive corporate-wide target was established to reduce carbon emissions by 75% by 2035 from a 2019 base year.

Additionally, FortisBC has committed to reduce customer emissions by 30% by 2030, one of the most ambitious targets in the Canadian utility sector. ITC Holdings Corp., the largest independent transmission company in the U.S., is strategically located in the U.S. Midwest and has already connected approximately 6,800 MW of wind energy to its systems, with plans for more renewable interconnection in the years ahead.

By 2035 virtually all of Fortis assets will be comprised of energy delivery and renewable, carbon-free generation.



(1) Predominantly natural gas generation

A Continuing Focus on Inclusion and Diversity

We recognize that an inclusive and diverse workplace inspires innovation, attracts bright minds and supports employee well-being. Our approach to inclusion and diversity is grounded in respect, our eagerness to listen and learn and our drive for change.

In 2020 we created an Inclusion and Diversity Council that includes representatives with diverse lived experiences from across our utilities. The purpose of the Council is to guide our inclusion and diversity strategy and its implementation.

During a year where our communities experienced social unrest and protests for equality, empowerment and dignity, we reaffirmed our commitment to doing what is right and influencing positive actions. Fortis signed the BlackNorth Initiative pledge in 2020, joining other senior leaders from public corporations to end systemic anti-Black racism.

Our focus on gender diversity continued in 2020. Women represent 40% of Fortis Inc. Board members elected in 2020, 42% of executives at head office and 60% of Fortis utilities have either a female CEO or Board Chair.

Leadership Succession

On December 31, 2020, Barry Perry retired as President and CEO of Fortis. Barry spent over 20 years of his career with the company, assuming the role of President and CEO in 2015.

His vision for Fortis resulted in the company's strategic expansion in the U.S., doubling its size and becoming a North American utility leader. During his leadership, Fortis total shareholder return was 104%, or approximately 12% per year.

We thank Barry for his leadership, integrity and drive to grow Fortis into the company it is today. His accomplishments were extraordinary and his guidance, commitment to excellence and humble nature have left a lasting impression on the culture of Fortis.

A Premium North American Energy Delivery Company

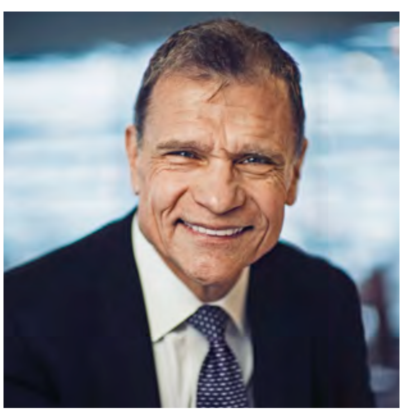
2020 demonstrated the depth of our talent and what we can achieve when we come together as one strong company. Employee safety and local community needs will continue to guide our pandemic response in 2021 as Fortis utilities maintain reliable energy delivery for our customers.

Our long-term strategy leverages our unique operating model, sustainability profile, geographic and regulatory diversity, operating expertise, reputation and financial strength. We see tremendous potential in our industry and we are well positioned to drive innovation and take advantage of exciting new opportunities.

Our growth platform is stronger than ever, and it supports our efforts to deliver a cleaner energy future as well as dividend growth and stability to shareholders. As we look back on 2020, we want to express our gratitude to our shareholders who have invested in our future. Thank you for your confidence in Fortis.

On behalf of the Board of Directors,

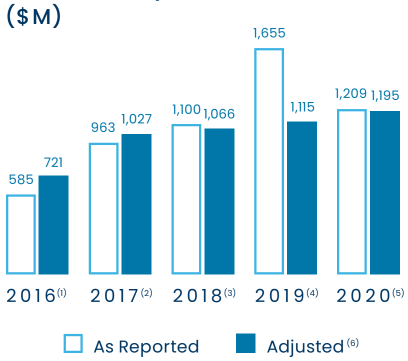
Douglas J. Haughey
Chair of the Board
Fortis Inc.



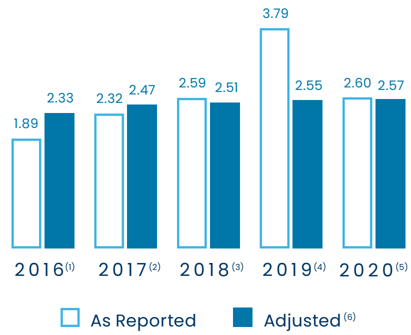
David G. Hutchens
President and CEO
Fortis Inc.

Financial Highlights

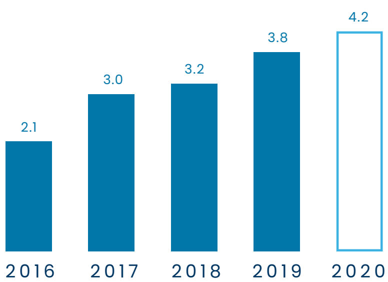
NET EARNINGS ATTRIBUTABLE TO COMMON EQUITY SHAREHOLDERS ($M)



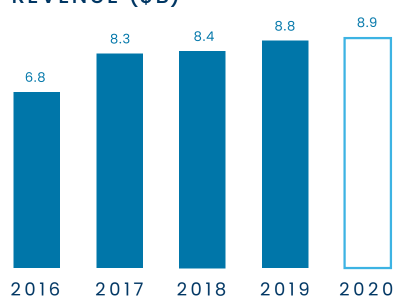
BASIC EARNINGS PER COMMON SHARE ($)



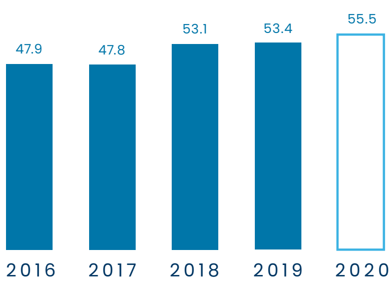
CAPITAL EXPENDITURES ($B)



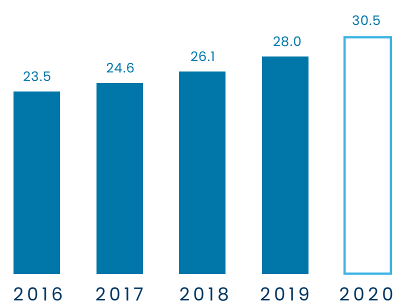
REVENUE ($B)



ASSETS ($B)



MIDYEAR RATE BASE ($B)



(1) Results were impacted by accretion associated with the acquisition of ITC in October 2016 and Aitken Creek in April 2016, as well as associated acquisition-related costs. Adjusted net earnings exclude acquisition-related costs and other non-operating items.

(2) Results were impacted by a full year's contribution from ITC and Aitken Creek. Adjusted net earnings exclude the impact of U.S. tax reform and other non-operating items.

(3) Results were tempered by the ongoing impact of U.S. tax reform and a reduced independence incentive adder at ITC. Adjusted net earnings exclude certain non-operating items.

(4) Results were impacted by a gain on disposition of the Waneta Expansion and a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the gain on disposition, the favourable regulatory adjustment and other non-operating items.

(5) Results were impacted by a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the favourable regulatory adjustment and certain non-operating items.

(6) Non-GAAP measure

All financial information is presented in Canadian dollars. Information is for the fiscal years ended December 31.

Highly Regulated, Low-Risk and Diversified Utility Business

REGULATED

	CUSTOMERS ELECTRIC (#)	CUSTOMERS GAS (#)	EMPLOYEES (#)	PEAK DEMAND ELECTRIC (MW)	PEAK DEMAND GAS (TJ)	ELECTRIC SALES (GWh)	GAS VOLUMES (PJ)	EARNINGS ($M)	TOTAL ASSETS ($B)	2021F (1) MIDYEAR RATE BASE ($B)	2021F (1) CAPITAL PROGRAM ($M)
ITC (2)	–	–	699	23,364	–	–	–	449	20.4	9.9	1,000
UNS Energy	532,000	163,000	2,057	3,309	107	16,763	15	302	10.8	6.2	749
Central Hudson	300,000	80,000	1,061	1,142	121	4,969	23	91	3.9	2.3	306
FortisBC (3)	182,000	1,048,000	2,514	740	1,555	3,291	219	231	10.1	6.7	620
FortisAlberta	572,000	–	1,085	2,770	–	16,092	–	133	5.1	3.8	346
Other Electric (4)	468,000	–	1,422	2,050	–	9,175	–	112	4.3	3.3	721
	2,054,000	**1,291,000**	**8,838**	**33,375**	**1,783**	**50,290**	**257**	**1,318**	**54.6**	**32.2**	**3,742**

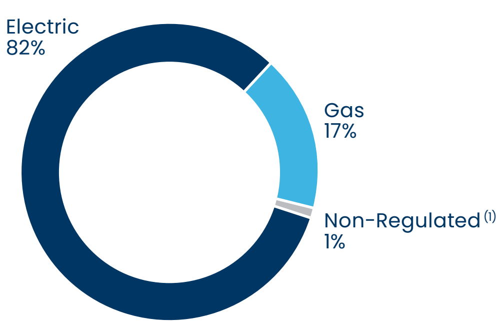
(1) Forecast

(2) Data reflects 100% of ITC's operations except for earnings, which represent the Corporation's 80.1% ownership interest. ITC has no retail customers.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Data reflects 100% of Caribbean Utilities' operations except earnings, which represent the Corporation's 60% ownership interest. Also includes Newfoundland Power, Maritime Electric, FortisOntario, a 39% equity investment in Wataynikaneyap Power Limited Partnership, Fortis Turks and Caicos, and a 33% equity investment in Belize Electricity.

99% REGULATED UTILITIES



ASSETS

Total Assets of **$55 billion** as of December 31, 2020.

(1) Comprising of energy infrastructure investments in British Columbia and Belize.

Management Discussion and Analysis

Contents

About Fortis ... 16
Significant Items ... 18
Performance at a Glance ... 19
The Industry ... 22
Operating Results ... 23
Business Unit Performance ... 24
ITC ... 24
UNS Energy ... 25
Central Hudson ... 25
FortisBC Energy ... 26
FortisAlberta ... 26
FortisBC Electric ... 27
Other Electric ... 27
Energy Infrastructure ... 27
Corporate and Other ... 28
Non-US GAAP Financial Measures ... 28
Regulatory Highlights ... 29
Financial Position ... 31
Liquidity and Capital Resources ... 32
Cash Flow Requirements ... 32
Cash Flow Summary ... 33
Contractual Obligations ... 35
Capital Structure and Credit Ratings ... 36
Capital Plan ... 36
Business Risks ... 39
Accounting Matters ... 46
Financial Instruments ... 49
Long-Term Debt and Other ... 49
Derivatives ... 49
Selected Annual Financial Information ... 51
Fourth Quarter Results ... 52
Summary of Quarterly Results ... 53
Related-Party and Inter-Company Transactions ... 54
Management's Evaluation of Controls and Procedures ... 55
Outlook ... 55
Forward-Looking Information ... 56
Glossary ... 57
Annual Consolidated Financial Statements ... 59

Dated February 11, 2021

This MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. It should be read in conjunction with the 2020 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 56. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

Financial information herein has been prepared in accordance with US GAAP (except for indicated Non-US GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following US dollar-to-Canadian dollar exchange rates: (i) average of 1.34 and 1.33 for the years ended December 31, 2020 and 2019, respectively; (ii) 1.27 and 1.30 as at December 31, 2020 and 2019, respectively; (iii) average of 1.30 and 1.32 for the quarters ended December 31, 2020 and 2019, respectively; and (iv) 1.32 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 57.

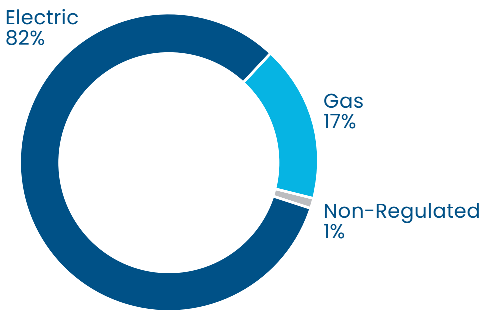
ABOUT FORTIS

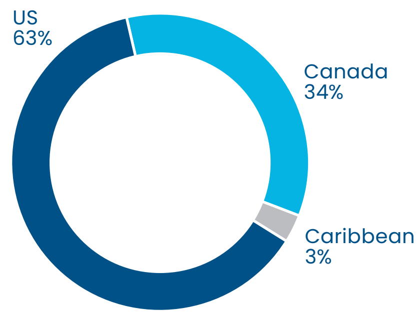

Jocelyn Perry, EVP, CFO, Fortis

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

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,000 employees serve 3.3 million utility customers in five Canadian provinces, nine US states and three Caribbean countries. As at December 31, 2020, 66% of the Corporation's assets were located outside Canada and 59% of 2020 revenue was derived from foreign operations.

TOTAL ASSETS AT DECEMBER 31, 2020





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

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

Non-regulated energy infrastructure consists of Aitken Creek (natural gas storage facility – British Columbia), BECOL (three hydroelectric generation facilities – Belize) and the Waneta Expansion up to its disposition in April 2019.

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

Fortis strives to provide safe, reliable and cost-effective energy service to customers using sustainable practices while delivering long-term profitable growth to shareholders. Management is focused on achieving growth through the execution of its capital plan and the pursuit of investment opportunities within and proximate to its service territories.

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

SIGNIFICANT ITEMS

COVID-19 Pandemic

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

Excluding the impact of the delay in TEP's general rate application (see "Regulatory Highlights" on page 29), the COVID-19 Pandemic did not have a material impact on the Corporation's capital expenditures, revenue or earnings in 2020. The financial impact to Fortis approximated $0.05 per common share and reflected: (i) reduced sales in the Caribbean; and (ii) higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

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

Revenue

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

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

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

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

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

Capital Expenditures

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

Liquidity

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

Fortis and its utilities continue to be successful in accessing capital markets. See "Liquidity and Capital Resources" on page 32.

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

The unfavourable impact on cash flow in 2020 associated with slower collection of customer balances was offset by other changes in Operating Cash Flow (see "Performance at a Glance – Operating Cash Flow" on page 21).

Regulatory Matters

Regulator and other stakeholder work schedule disruptions caused delays and postponements for certain regulatory proceedings in 2020. See "Regulatory Highlights" on page 29. The Corporation's significant regulatory proceedings, as discussed below, were concluded by the end of 2020.

Pension Plans

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

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

Outlook

The continued uncertainty surrounding the evolution of the pandemic makes it difficult to predict the ultimate operational and financial impacts on Fortis. Potential impacts are discussed under "Business Risks" on page 39.

Significant Regulatory Decisions

TEP Rate Order

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

FortisAlberta 2021 GCOC

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

November 2020 AUC Decision

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

See "Regulatory Highlights" on page 29 for further information on these significant regulatory developments.

PERFORMANCE AT A GLANCE

Key Financial Metrics

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

(1) See "Non-US GAAP Financial Measures" on page 28

(2) Includes Fortis' $138 million share of development costs and capital spending for the Wataynikaneyap Transmission Power Project

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

(1) Annualized TSR per Bloomberg, as at December 31, 2020

Earnings and EPS

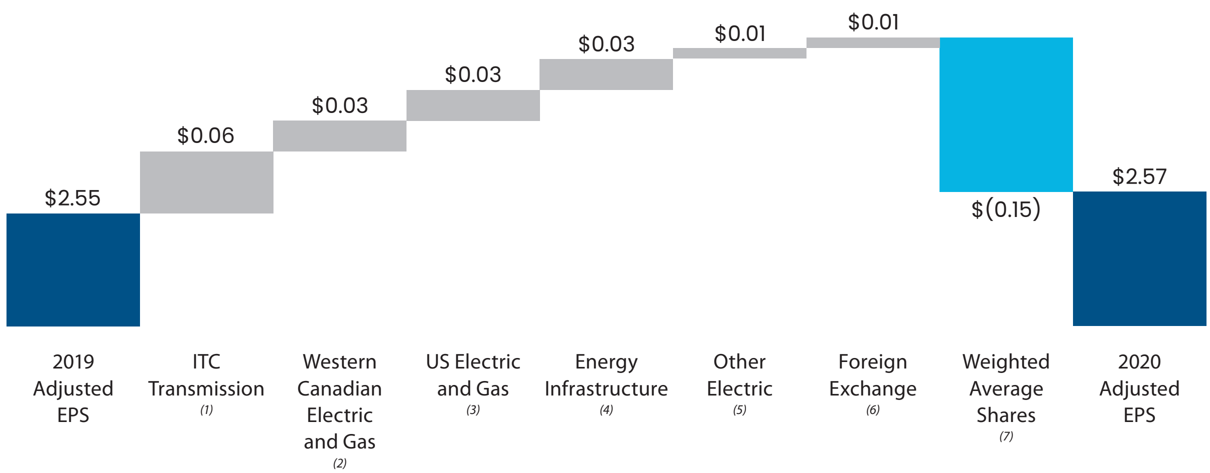
The $446 million decrease in Common Equity Earnings reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the November 2019 and May 2020 FERC decisions at ITC (see "Regulatory Highlights" on page 29).

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

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

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $80 million and $0.02, respectively. Refer to "Non-US GAAP Financial Measures" on page 28 for a reconciliation of these measures. The changes in Adjusted Basic EPS are illustrated in the chart below.

CHANGES IN ADJUSTED BASIC EPS



(1) Primarily reflects Rate Base growth and an increase in the base ROE

(2) FortisBC Energy, FortisBC Electric and FortisAlberta. Primarily reflects Rate Base and customer growth, partially offset by the elimination of the PBR efficiency carry-over mechanism at FortisAlberta

(3) UNS Energy and Central Hudson. Increase at UNS Energy reflects higher retail sales driven by favourable weather, partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates and higher net operational costs associated with the COVID-19 Pandemic. Increase at Central Hudson reflects Rate Base growth, partially offset by higher net operational expenses associated with the COVID-19 Pandemic.

(4) Primarily reflects increased hydroelectric production in Belize due to higher rainfall. Excludes the impact of the disposition of the Waneta Expansion, which was neutral on consolidated earnings

(5) Primarily reflects higher equity income from Belize Electricity and Rate Base growth, partially offset by the impacts of the COVID-19 Pandemic, particularly in the Caribbean

(6) Average foreign exchange rate of $1.34 in 2020 compared to $1.33 in 2019

(7) Weighted average shares of 464.8 million in 2020 compared to 436.8 million in 2019

Dividends and TSR

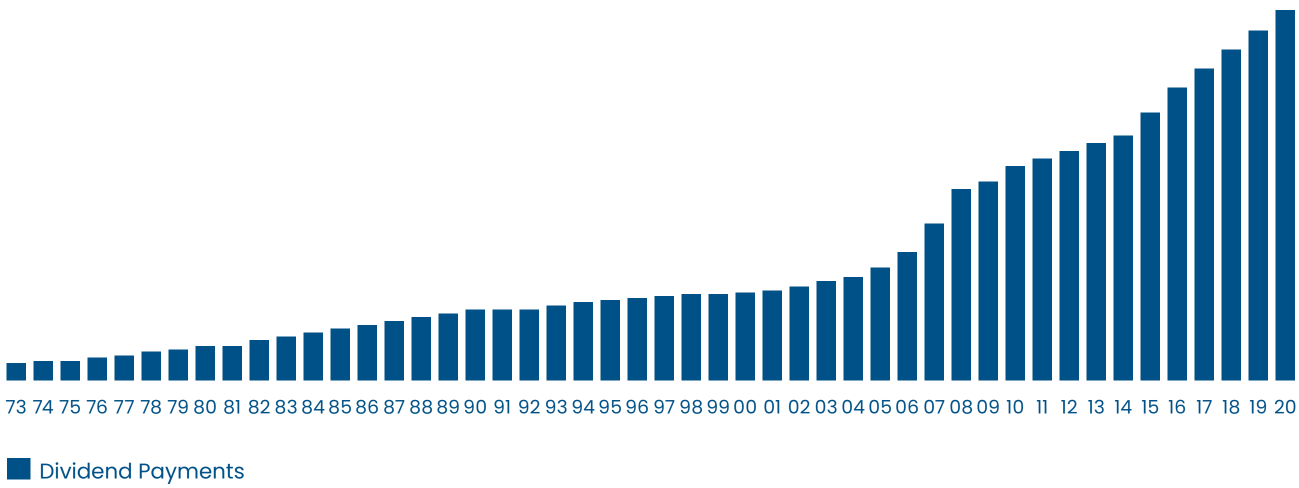
Fortis paid a dividend of $0.505 per common share in the fourth quarter of 2020, up from $0.4775 paid in each of the previous four quarters.

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

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

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

47 YEARS OF COMMON SHARE DIVIDEND INCREASES



Operating Cash Flow

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

Capital Expenditures

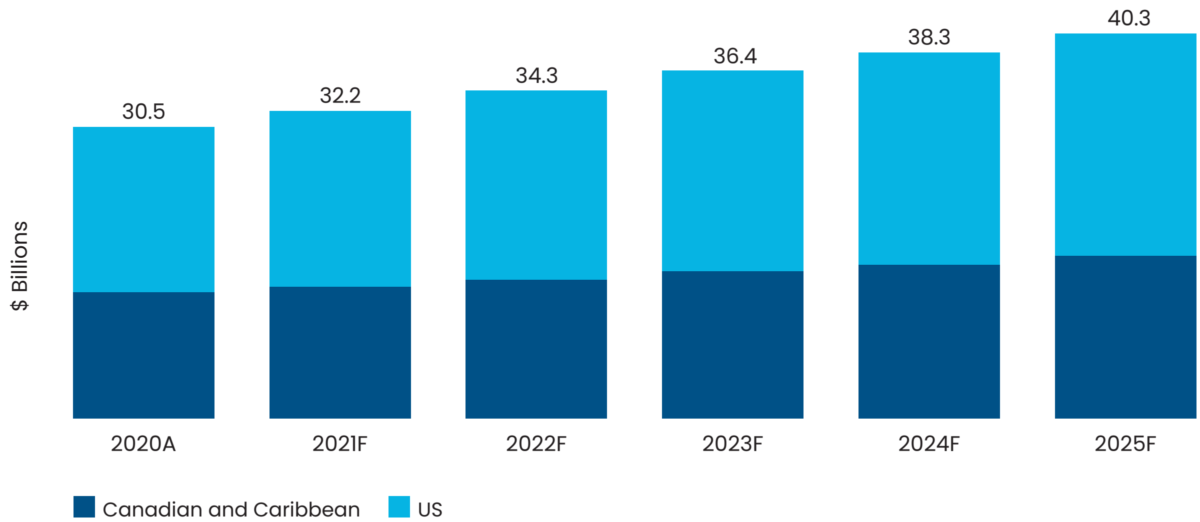
Capital expenditures in 2020 were $4.2 billion, $0.4 billion higher than in 2019 and broadly consistent with the 2020 capital plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 36.

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

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

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

PROJECTED RATE BASE GROWTH



Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

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

Energy policies at the federal, state and provincial levels also reflect the rising focus on climate change, with clean energy and carbon reduction initiatives at the forefront. The regulatory and compliance operating environment is also evolving and becoming increasingly complex. These changes are creating additional opportunities to expand investment in new generation sources, including solar and wind, as well as transmission infrastructure to interconnect renewable energy sources to the grid. Investment opportunities in storage are also growing with the proliferation of various renewable generation sources and decreasing costs of energy storage technology. The electrification of the transportation sector is a significant opportunity for reducing GHG emissions. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, additional grid automation, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology. Grid hardening and resiliency technology investments are increasing in importance due to climate volatility resulting from more frequent and severe storms, hurricanes and wildfires.

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

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

Meaningful customer engagement is increasingly important for utilities as customer expectations change and competition for customer attention becomes more intense. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized service offerings and more real-time, digital communication. Our utilities are capitalizing on this as an investment opportunity to provide enhanced customer information systems and digital technologies to improve customer service.

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

OPERATING RESULTS

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

Revenue

The increase in revenue was due primarily to: (i) overall higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) higher retail electricity sales driven by favourable weather in Arizona; and (iv) a $40 million favourable base ROE adjustment at ITC related to prior periods as a result of the May 2020 FERC decision. The increase was partially offset by: (i) a $91 million favourable base ROE adjustment at ITC in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower short-term wholesale sales at UNS Energy. See "Regulatory Highlights" on page 29 for further details on the November 2019 and May 2020 FERC decisions.

Energy Supply Costs

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

Operating Expenses

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

Depreciation and Amortization

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

Gain on Disposition

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

Other Income, Net

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

Finance Charges

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

Income Tax Expense

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

Net Earnings

See "Performance at a Glance – Earnings and EPS" on page 20.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

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

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

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

(3) Primarily consists of long-term contracted generation assets in Belize, Aitken Creek in British Columbia and, until its April 16, 2019 disposition, the Waneta Expansion

(4) Includes Fortis net corporate expenses and non-regulated holding company expenses

ITC

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

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

Revenue

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

Earnings

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

See "Regulatory Highlights" on page 29 for further information on the November 2019 and May 2020 FERC decisions.

UNS Energy

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

[(1)] Primarily short-term wholesale sales

Sales

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

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

Gas sales were comparable to 2019.

Revenue

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

Earnings

The increase in earnings, net of foreign exchange, was due primarily to higher retail electricity sales, partially offset by higher costs associated with Rate Base growth not reflected in customer rates in 2020. Beginning January 1, 2021, new customer rates are in effect following the conclusion of TEP's general rate application (see "Regulatory Highlights" on page 29). Higher net operational expenses associated with the COVID-19 Pandemic, including an increase in credit loss expense, also unfavourably impacted earnings.

Central Hudson

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

Sales

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

Gas sales were comparable to 2019.

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

Revenue

The increase in revenue, net of foreign exchange, was due primarily to an increase in gas and electricity delivery rates effective July 1, 2019 and July 1, 2020, reflecting a return on increased Rate Base assets as well as the recovery of higher operating and financing expenses (see "Regulatory Highlights" on page 29 for information on the July 1, 2020 rate increase). The increase was partially offset by the flow through of lower energy supply costs.

Earnings

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

FortisBC Energy

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

Sales

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

Revenue

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

Earnings

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

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

FortisAlberta

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

Deliveries

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

As more than 85% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Revenue

The decrease in revenue was due primarily to: (i) the impact of the AUC's November 2020 decision with respect to the 2018 Independent System Operator Tariff Application reflecting the flow through of lower depreciation costs with no material impact on earnings (see "Regulatory Highlights" on page 29); and (ii) the recognition of revenue in 2019 associated with the PBR efficiency carry-over mechanism. The decrease was partially offset by Rate Base growth and customer additions.

Earnings

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

FortisBC Electric

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

Sales

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

Revenue

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

Earnings

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

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

Other Electric

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

Sales

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

Revenue

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

Earnings

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

Energy Infrastructure

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

Sales

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

Revenue and Earnings

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

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

Corporate and Other

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

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

NON-US GAAP FINANCIAL MEASURES

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

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

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

Non-US GAAP Reconciliation

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

(1) Represents prior period impacts of the May 2020 and November 2019 FERC base ROE decisions, respectively (see "Regulatory Highlights" below), included in the ITC segment

(2) The finalization of US tax reform regulations associated with anti-hybrid regulations in 2020 and base-erosion and anti-abuse tax in 2019, included in the Corporate and Other segment

(3) Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment

(4) Gain on sale of the Waneta Expansion, net of expenses, in April 2019, included in the Corporate and Other segment

REGULATORY HIGHLIGHTS

General

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

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

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

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

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2020 Annual Financial Statements. Also refer to "Business Risks – Regulation" on page 40.

COVID-19 Pandemic Impacts

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

Customer Relief Initiatives

UNS Energy

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

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

Central Hudson

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

FortisBC Energy and FortisBC Electric

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

Delayed and Postponed Regulatory Proceedings

UNS Energy

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

Central Hudson

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

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

FortisAlberta

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

Other Electric

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

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

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

Significant Regulatory Developments

ITC

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

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

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

Central Hudson

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

FortisBC Energy and FortisBC Electric

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

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

FortisAlberta

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

In November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

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

FINANCIAL POSITION

Significant Changes between December 31, 2020 and 2019

	Increase (Decrease)		
Balance Sheet Account	**FX** *($ millions)*	**Other** *($ millions)*	**Explanation**
Cash and cash equivalents	(3)	(118)	Related to the timing of debt and equity issuances, and the related reinvestment in capital and operating requirements.
Regulatory assets (current and long-term)	(25)	230	Due primarily to deferred income taxes, and the operation of energy management cost and employee future benefits deferrals, partially offset by lower derivative loss deferrals at UNS Energy.
Property, plant and equipment, net	(425)	2,435	Due to capital expenditures, partially offset by depreciation.
Goodwill	(212)	–	
Short-term borrowings	(10)	(370)	Reflects the repayment of short-term borrowings at UNS Energy and commercial paper at ITC.
Other liabilities	(16)	169	Reflects employee future benefits, refundable deposits received by ITC for transmission network upgrades, and an upfront payment received by FortisAlberta associated with a long-term energy retailer agreement.
Regulatory liabilities (current and long-term)	(48)	(207)	Due to ROE complaints liability at ITC, deferred income taxes, and the normal operation of rate stabilization and related accounts.
Deferred income tax liabilities	(34)	409	Due to higher temporary differences associated with ongoing capital investment.
Long-term debt (including current portion)	(296)	2,472	Reflects debt issuances, partially offset by debt repayments at the regulated utilities, largely at ITC and UNS Energy.
Shareholders' equity	(279)	445	Due primarily to: (i) Common Equity Earnings for 2020, less dividends declared on common shares; and (ii) the issuance of common shares.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will be paid from Operating Cash Flow, with varying levels of residual cash flow available for capital expenditures and/or dividend payments to Fortis. Capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements and there could be higher-than-normal working capital deficiencies in the short term, as the ongoing impacts of the COVID-19 Pandemic affect customers' ability to pay their energy bills. See "Business Risks" on page 39.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's committed credit facility, proceeds from the DRIP and issuances of common shares, preference equity and long-term debt. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. Both Fortis and its subsidiaries initially borrow through their committed credit facilities and periodically replace these borrowings with long-term debt. Financing needs also arise periodically for acquisitions and to refinance maturing debt.

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

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

Credit Facilities

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

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

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

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

In December 2020, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $2.0 billion. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity due, in part, to its $1.2 billion common equity offering and sale of the Waneta Expansion in 2019. See "Cash Flow Summary – Financing Activities" on page 33.

This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2021.

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

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

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

Operating Activities

See "Performance at a Glance – Operating Cash Flow" on page 21.

Investing Activities

Cash used in investing activities reflects higher capital expenditures in 2020. See "Performance at a Glance – Capital Expenditures" on page 21 and "Capital Plan" on page 36. Cash used in investing activities in 2019 was partially offset by proceeds from the Waneta Expansion disposition.

Financing Activities

Cash flow related to financing activities will fluctuate largely as a result of changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, which together impact the amount of funding required from debt and common equity issuances. See "Cash Flow Requirements" on page 32.

In the fourth quarter of 2019, the Corporation issued approximately 22.8 million common shares at a price of $52.15 per share for gross proceeds of $1,190 million ($1,167 million net of commissions). The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured senior notes due October 4, 2021, to repay credit facility borrowings and for general corporate purposes. Also in 2019, net proceeds of $995 million from the April 2019 Waneta Expansion disposition were used to repay credit facility borrowings and repurchase, via a tender offer, US$400 million of its outstanding 3.055% unsecured senior notes due in 2026.

Debt Financing

Long-Term Debt Issuances

Year ended December 31, 2020 *($ millions, except %)*	Month Issued	Interest Rate *(%)*	Maturity	Amount	Use of Proceeds
ITC					
Unsecured term loan credit agreement	January	(1)	2021	US 75	(2) (3)
Unsecured term loan credit agreement (4)	January	(5)	2021	US 200	(4)
Unsecured senior notes	May	2.95	2030	US 700	(2) (3) (6)
First mortgage bonds	July	3.13	2051	US 180	(2) (3) (7)
Secured senior notes	October	3.02	2055	US 150	(2) (3) (7) (8)
UNS Energy					
Unsecured senior notes	April	4.00	2050	US 350	(2) (3)
Unsecured senior notes	August	1.50	2030	US 300	(7)
Unsecured senior notes	September	2.17	2032	US 50	(2) (3)
Central Hudson					
Unsecured senior notes	May	3.42	2050	US 30	(3)
Unsecured senior notes	July	3.62	2060	US 30	(3) (7)
Unsecured senior notes	September	2.03	2030	US 40	(8)
Unsecured senior notes	November	2.03	2030	US 30	(3) (7)
FortisBC Energy					
Unsecured debentures	July	2.54	2050	200	(7)
FortisAlberta					
Unsecured senior debentures	December	2.63	2051	175	(2)
FortisBC Electric					
Unsecured debentures	May	3.12	2050	75	(2)
Newfoundland Power					
First mortgage sinking fund bonds	April	3.61	2060	100	(2) (3)
FortisTCI					
Unsecured senior notes	June/October	5.30	2035	US 30	(7) (8)
Unsecured senior notes	October/December	3.25	2030	US 10	(3)

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

Common Equity Financing

Common Equity Issuances and Dividends Paid

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

(1) Includes common shares issued under stock option and employee share purchase plans. For 2019, mainly reflects the issuance of shares in December 2019 and through the ATM Program.
(2) Common shares issued under the DRIP and stock option plan. Effective March 1, 2020, the 2% discount offered on common share issuances under the DRIP was terminated and effective December 1, 2020 was reinstated. See "Cash Flow Requirements" on page 32 for further information.
(3) Common share dividends reinvested under the DRIP

On February 11, 2021, Fortis declared a dividend of $0.505 per common share payable on June 1, 2021. The payment of dividends is at the discretion of the board of directors and depends on the Corporation's financial condition and other factors.

Contractual Obligations

Contractual Obligations

As at December 31, 2020

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

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

(2) Additional information is provided in Note 15 in the 2020 Annual Financial Statements.

(3) Additional information is provided in Note 28 in the 2020 Annual Financial Statements.

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Consolidated capital expenditures are forecast to be approximately $3.8 billion for 2021 and approximately $19.6 billion over the five-year 2021–2025 capital plan. See "Capital Plan" on page 36.

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

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

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

As at December 31, 2020, FortisBC Holdings Inc., a non-regulated holding company, had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $130 million as at December 31, 2020 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

Capital Structure and Credit Ratings

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

Consolidated Capital Structure *(%)*

As at December 31	2020	2019
Debt [1]	**54.8**	53.1
Preference shares	**3.6**	3.8
Common shareholders' equity and minority interest [2]	**41.6**	43.1
	100.0	100.0

[1] Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash

[2] Includes minority interest of 3.5% as at December 31, 2020 (2019 – 3.7%)

Outstanding Share Data

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

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

If all outstanding stock options were converted as at February 11, 2021, an additional 3.3 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.

Credit Ratings

As at December 31, 2020	Rating	Type	Outlook
S&P	A–	Corporate	Negative
	BBB+	Unsecured debt	
DBRS Morningstar	BBB (high)	Corporate	Positive
	BBB (high)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

Capital Plan

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth.

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

2020 Capital Expenditures [1]

	Regulated Utilities										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**	***(%)***
Generation	–	639	–	–	–	26	42	**707**	**5**	**712**	**17**
Transmission	1,070	84	48	138	–	34	165	**1,539**	**–**	**1,539**	**37**
Distribution	–	330	188	207	333	46	167	**1,271**	**–**	**1,271**	**30**
Other [3]	112	147	103	126	87	29	37	**641**	**14**	**655**	**16**
Total	1,182	1,200	339	471	420	135	411	**4,158**	**19**	**4,177**	**100**
(%)	29	29	8	11	10	3	10	**100**	**–**	**100**	

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

[2] Includes Energy Infrastructure and Corporate and Other segments

[3] Includes facilities, equipment, vehicles and information technology assets, as well as AESO transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, labour and material costs, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast or plan. The impact of the COVID-19 Pandemic on forecast capital expenditures will continue to be evaluated and, depending on the length and severity of the pandemic, certain planned expenditures may shift within the 2021–2025 capital plan.

Forecast 2021 Capital Expenditures [1]

	Regulated Utilities										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated**	**Total**	***(%)***
Generation	–	117	1	–	–	24	189	**331**	**53**	**384**	**10**
Transmission	949	191	41	168	–	23	310	**1,682**	**–**	**1,682**	**44**
Distribution	–	270	167	184	266	81	173	**1,141**	**–**	**1,141**	**30**
Other	51	171	97	115	80	25	49	**588**	**18**	**606**	**16**
Total	1,000	749	306	467	346	153	721	**3,742**	**71**	**3,813**	**100**
(%)	26	20	8	12	9	4	19	**98**	**2**	**100**	

[1] Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment

Five-Year Capital Plan [1]

($ billions)	2021	2022	2023	2024	2025	**Total**
	3.8	3.9	3.9	4.0	4.0	**19.6**

[1] Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.

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

The capital plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 15% related to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the US, including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Nature of Capital Expenditures

(%)	**Actual 2020**	Forecast 2021	Five-Year Plan 2021–2025
Growth [1]	**21**	31	26
Sustaining [2]	**65**	54	58
Other [3]	**14**	15	16
Total	**100**	100	100

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

Midyear Rate Base [1]

($ billions)	**2020**	2021	2025
ITC	**9.5**	9.9	12.5
UNS Energy	**5.7**	6.2	7.6
Central Hudson	**2.1**	2.3	3.2
FortisBC Energy	**5.1**	5.2	6.8
FortisAlberta	**3.7**	3.8	4.2
FortisBC Electric	**1.4**	1.5	1.7
Other Electric	**3.0**	3.3	4.3
Total	**30.5**	32.2	40.3

[1] Simple average of Rate Base at beginning and end of the year

Total midyear Rate Base is forecast to grow to $40.3 billion by 2025 under the five-year capital plan, representing a CAGR of approximately 6.0%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects[1]

($ millions)	Project	Pre-2020	Actual 2020	Forecast 2021	Forecast 2022–2025	Expected Completion
ITC[2]	Multi-Value Regional Transmission Projects	625	**17**	75	186	2023
	34.5 to 69 kV Transmission Conversion Project	352	**93**	41	107	Post-2025
UNS Energy	Vail-to-Tortolita Project	–	**–**	54	190	2023
	Oso Grande Wind Project	65	**509**	24	–	2021
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade	388	**23**	18	–	2021
	Eagle Mountain Woodfibre Gas Line Project[3]	–	**–**	–	350	2025
	Transmission Integrity Management Capabilities Project	13	**8**	7	434	Post-2025
	Inland Gas Upgrades Project	9	**50**	53	177	2025
	Tilbury 1B	8	**12**	1	375	2025
	Tilbury LNG Resiliency Tank	–	**10**	11	198	Post-2025
	AMI Project	–	**–**	4	243	Post-2025
Other Electric	Wataynikaneyap Transmission Power Project[4]	40	**138**	330	206	2023
Total			**860**	618	2,466	

(1) Includes applicable AFUDC

(2) Pre-2020 capital expenditures are from the date of the ITC acquisition on October 14, 2016

(3) Net of forecast customer contributions

(4) Fortis' share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.

Multi-Value Regional Transmission Projects

Four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects were completed pre-2020. The fourth project is expected to be placed in service in 2023.

34.5 to 69 kV Transmission Conversion Project

Multiple capital initiatives designed to construct new 69 kV lines, upgrade existing 34.5 kV lines to 69 kV, and complete substation conversions with in-service dates ranging from pre-2020 to post-2025.

Vail-to-Tortolita Project

A phase of the Southline Transmission Project that consists of new construction and upgrades to connect existing TEP substations. The project includes the construction of a new 230 kV line within TEP's service territory. Construction is expected to begin in early 2022 with an in-service date of 2023.

Oso Grande Wind Project

Construction of a 750 MW wind-powered electric generating facility that complements UNS Energy's existing renewable solar generation portfolio, of which UNS Energy owns 250 MW. Construction is expected to be completed and the facility placed in service in the first half of 2021.

Lower Mainland Intermediate Pressure System Upgrade

Addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The project is substantially complete, with one pipeline segment to be replaced in 2021. Final allowable project costs are subject to review by the BCUC.

Eagle Mountain Woodfibre Gas Line Project

Gas line expansion to a proposed LNG site in Squamish, British Columbia. In March 2020 Woodfibre LNG Limited, the owner of the proposed LNG facility, requested an extension to its British Columbia Environmental Assessment Certificate due to production and supply chain disruptions resulting, in part, from the COVID-19 Pandemic. In October 2020, the BC Environmental Assessment Certificate was extended for another five years.

FortisBC Energy's proposed pipeline expansion remains contingent on Woodfibre LNG Limited making a final decision to proceed with construction of the LNG facility. At this time, should the project proceed, the earliest construction start date expected is late-2021.

Transmission Integrity Management Capabilities Project

This project improves gas line safety and transmission system integrity, including gas line modifications and looping. A CPCN application is expected to be filed with the BCUC in the first quarter of 2021.

Inland Gas Upgrades Project

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

Tilbury 1B Project

Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. The project received an Order in Council from the Government of British Columbia in 2017. In February 2020 an initial project scope was filed with regulators to begin the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2021.

Tilbury LNG Resiliency Tank

This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. In December 2020 FortisBC Energy filed a CPCN application for this project with the BCUC.

AMI Project

Replacement of residential and small commercial meters and installation of bypass valves to avoid future interruption of gas service. The project will assist in load management by allowing remote meter reading on a near real-time basis and remote shutoff of gas flow. FortisBC Energy plans to file a CPCN application for this project with the BCUC in the first half of 2021.

Wataynikaneyap Transmission Power Project

Construction of a 1,800 kilometre, Ontario Energy Board regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid, in which Fortis holds a 39% equity interest. FortisOntario is responsible for construction management and operation of the transmission line. The project is on track with completion expected in 2023.

Additional Investment Opportunities

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

ITC – Lake Erie Connector

Proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line to directly link the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. The major permits have been approved. The project continues to advance through regulatory, operational and economic milestones. Ongoing activities include completing project cost refinements and securing transmission service agreements. Completion would take approximately four years from the commencement of construction.

FortisBC Energy – LNG

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

Other Opportunities

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

BUSINESS RISKS

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

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

Regulation

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2020. Regulatory jurisdictions include five Canadian provinces, nine US states and three Caribbean countries, as well FERC regulation for transmission assets in the US.

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

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

For transmission operations, the underlying elements of FERC-established formula rates can be, and have been, challenged by third parties which could result in, and has resulted in, lowered rates and customer refunds. These underlying elements include the assumed ROE, ROE adders for independent transmission ownership and deemed capital structure as well as operating and capital expenditures. These challenges could have a Material Adverse Effect.

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

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

Climate Change and Physical Risks

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

Climate change is predicted to lead to more frequent and intense weather events, changing air temperatures, changing seasonal variations, and regulatory responses (see "Environmental Matters" on page 41), each of which could have a Material Adverse Effect. Severe weather impacts the Corporation's service territories, primarily when thunderstorms, flooding, wildfires, hurricanes and snow or ice storms occur. Increased frequency of extreme weather events could increase the cost of providing service. Changes in precipitation that result in droughts could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Changing air temperatures could also result in system stress and decreased efficiencies to operating facilities over time. Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels and larger storm surges, could result in service disruption, repair and replacement costs, and costs associated with strengthened design standards and systems, each of which could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

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

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

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

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

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

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

Pandemics and Public Health Crises, including the COVID-19 Pandemic

The Corporation could be negatively impacted by a widespread outbreak of communicable diseases or other public health crises that cause economic and/or other disruptions. The COVID-19 Pandemic continues to be an evolving situation that has adversely impacted economic activity and conditions around the world, including the Corporation's service territories (see "General Economic Conditions" on page 46 and "Access to Capital" on page 45). The virus and efforts to reduce the health impacts and control its spread have led many jurisdictions around the world, including Canada, the US and the Caribbean, to institute restrictions on travel, gatherings and business operations. The Corporation and its utilities have been subjected to government and regulatory action in response to the COVID-19 Pandemic, including restrictions on business operations, customer deferrals and suspension of disconnections. Other potential impacts on the Corporation's operations may include reduced labour availability and productivity, disruptions to capital markets leading to share price volatility and liquidity issues, supply chain disruptions, project construction delays and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill.

The overall impact will depend on the duration and severity of the pandemic, potential government actions to mitigate public health effects or aid economic recovery, and other factors beyond the Corporation's control. An extended period of economic disruption could have a Material Adverse Effect.

Environmental Matters

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

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

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

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

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

Growth

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

The Corporation's dividend growth guidance is significantly dependent upon achieving the Rate Base growth expected from the execution of the five-year capital plan described under "Capital Plan" on page 36. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, supply and labour costs, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation's control. There is no assurance that regulators will approve: (i) all of the planned projects or their amounts or timing; (ii) permits in a timely manner, or with reasonable terms and conditions; or (iii) the recovery of cost overruns in customer rates. These risks could impact the successful execution of a project by preventing the project from proceeding, delaying its completion, increasing its projected costs or negatively impacting its financing.

Weather Variability and Seasonality

Electricity consumption varies significantly in response to climate change and seasonal weather changes (see "Climate Change and Physical Risks" on page 40). In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability.

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

Hydroelectric generation is sensitive to rainfall levels.

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

Natural Gas Competitiveness

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

In British Columbia, which accounts for 80% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive, the ability to add new customers could be impaired. Existing customers could also reduce their consumption or switch to electricity, placing further pressure on rates, whereby system costs must be recovered from a smaller customer and sales base, leading to further reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. The provincial government has introduced changes to energy policy, including GHG emission reduction targets and a tax on carbon-based fuels which is expected to increase in the future. However, the Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. As all levels of government become more active in the development of policies to address climate change, any resultant changes to energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon based energy sources or other energy sources.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source, and type of housing stock being built. In addition, as part of their own climate change policy plans, local governments may use various tools at their disposal such as franchise agreements, permits, building codes and zoning bylaws to impose limitations on energy sources permitted in new and existing developments. The municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free options for their developments. These actions and policies may hinder the Corporation's ability to attract new customers or retain existing customers.

Commodity Price Volatility

Purchased power and generation fuel costs are subject to commodity price volatility, which is managed through regulator-approved: (i) mechanisms that permit the flow through in customer rates of commodity price changes and/or that provide for rate-stabilization and other deferral accounts (see "Business Unit Performance" on page 24); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments – Derivatives" on page 49).

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

Purchased Power Supply

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

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates and other approvals from various levels of government, regulators, government agencies, Indigenous Peoples and/or third parties. The external environment has become more complex with heightened expectations from permitting agencies, local municipalities and Indigenous Peoples to be able to review and provide feedback on projects, largely driven by policy responses to climate change. There is no assurance that: (i) all of these approvals will be obtained, continuously maintained or renewed without delay; and (ii) the terms and conditions thereof will be fully complied with at all times and will not change in a material adverse manner. Significant failures in these regards could prevent the operation of the businesses and have a Material Adverse Effect.

Reliability Standards

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

Indigenous Peoples' Land Claims

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

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

Joint-Ownership Interests and Third-Party Operators

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

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

Counterparty Credit Risk

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

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

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

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

Cybersecurity

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

Information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.

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

Technology Advances

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

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

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

Interest Rates

Generally, the market price of the Corporation's common shares is inversely sensitive to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates. A low interest rate environment could reduce allowed ROEs. Alternatively, if interest rates rise, regulatory lag may cause delays in any compensatory ROE increases. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes.

Tax Laws

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

Foreign Exchange Exposure

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

Fortis has limited this exposure through hedging. As at December 31, 2020, US$2.3 billion (2019 – US$2.2 billion) of corporately issued US dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$10.2 billion (2019 – US$9.7 billion) in foreign net investments unhedged. Fortis has also entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, consolidated earnings and cash flow continue to be impacted by exchange rate fluctuations. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CA$1.34 as at December 31, 2020 would increase or decrease annual EPS by approximately six cents, which reflects the Corporation's hedging program.

The Corporation's $19.6 billion five-year capital plan for 2021 through 2025 also includes exposure to foreign exchange. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar would increase or decrease capital expenditures by $400 million over the five-year planning period.

There is no assurance that existing hedging strategies will continue to be effective and the resultant financial impacts could have a Material Adverse Effect.

Access to Capital

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

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

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

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 32.

Insurance

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

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

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of skilled workforces. Like its peers, Fortis faces demographic challenges and competitive markets relating to trades, technical and professional staff, particularly considering its significant capital plan. ITC relies heavily on agreements with third parties to provide services for the construction, maintenance and operation of certain aspects of its business. Significant failures in attracting or retaining a skilled workforce could have a Material Adverse Effect.

Labour Relations

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

Post-Retirement Obligations

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

General Economic Conditions

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

Reputation, Relationships and Stakeholder Activism

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

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

Legal, Administrative and Other Proceedings

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

ACCOUNTING MATTERS

New Accounting Policies

Financial Instruments

Effective January 1, 2020, the Corporation adopted ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimation of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The new guidance also requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. Adoption did not have a material impact on the 2020 Annual Financial Statements and related disclosures. Further information is provided in Note 3 in the 2020 Annual Financial Statements.

Critical Accounting Estimates

General

The preparation of the 2020 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulatory Assets and Liabilities

As at December 31, 2020, Fortis recognized regulatory assets of $3.6 billion (2019 – $3.4 billion) and regulatory liabilities of $3.1 billion (2019 – $3.4 billion).

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

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

Employee Future Benefits

Key Estimates and Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
Years ended December 31	**2020**	2019	**2020**	2019
Funded status:[1] *($ millions)*				
Benefit obligation[2]	**(3,995)**	(3,632)	**(789)**	(712)
Plan assets	**3,528**	3,208	**391**	343
	(467)	(424)	**(398)**	(369)
Net benefit cost[2] *($ millions)*	**67**	65	**32**	28
Key assumptions: *(weighted average %)*				
Discount rate:[3]				
During the year	**3.16**	4.05	**3.22**	4.10
As at December 31	**2.63**	3.20	**2.64**	3.25
Expected long-term rate of return on plan assets[4]	**5.52**	5.78	**5.28**	5.50
Rate of compensation increase	**3.34**	3.33	**–**	–
Health care cost trend increase rate[5]	**–**	–	**4.61**	4.62

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

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

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

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

(5) Actuarially determined, the projected 2021 rate is 5.91% and is assumed to decrease over the next 11 years to the ultimate rate of 4.61% in 2031 and thereafter.

Sensitivity Analysis

Year ended December 31, 2020	Rate of Return – 1% change		Discount Rate – 1% change		Health Care Costs Trend Rate – 1% change	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined benefit pension plans:						
Net benefit cost	**(30)**	**25**	**(45)**	**63**	**n/a**	**n/a**
Projected benefit obligation	**44**	**(82)**	**(541)**	**691**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(9)**	**13**	**29**	**(21)**
Accumulated benefit obligation	**–**	**–**	**(113)**	**144**	**106**	**(84)**

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

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

Depreciation and Amortization

As at December 31, 2020, Fortis recognized property, plant and equipment and intangible assets of $37.3 billion (2019 – $35.2 billion) representing 67% of total assets (2019 – 66%). Depreciation and amortization totalled $1.4 billion for 2020 (2019 – $1.4 billion).

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

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future asset removal costs not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2020, this regulatory liability was $1.2 billion (2019 – $1.2 billion).

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

Goodwill Impairment

As at December 31, 2020, Fortis recognized goodwill of $11.8 billion (2019 – $12.0 billion), representing 21% of total assets (2019 – 22%). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill.

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

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

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

Although the macro-economic impact of the COVID-19 Pandemic is pervasive throughout each reporting unit's service territory, it is expected to be short term in nature and therefore not expected to have a material impact on long-term sustaining cash flows. No goodwill impairment was recognized in 2020 or 2019, pursuant to the annual assessments.

Income Tax

As at December 31, 2020, deferred income tax liabilities, current income tax receivable included in accounts receivable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $3.3 billion, $72 million, $1.7 billion and $1.4 billion, respectively (2019 – $3.0 billion, $35 million, $1.6 billion and $1.4 billion, respectively). Income tax expense was $231 million in 2020 (2019 – $289 million).

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

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

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

Derivatives

The fair values of derivatives are based on estimates that cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting future earnings or cash flows. See "Financial Instruments – Derivatives" on page 49.

Contingencies

The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks – Indigenous Peoples' Land Claims" on page 43, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 28 in the 2020 Annual Financial Statements.

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

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2020, the carrying value of long-term debt, including the current portion, was $24.5 billion (2019 – $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 – $25.3 billion). Since Fortis does not intend to settle long-term debt prior to maturity, the excess of fair value over carrying value does not represent an actual liability.

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

Derivatives

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

Energy contracts subject to regulatory deferral

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

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2020, unrealized losses of $73 million (2019 – $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 – $2 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

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

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

Total return swaps

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

Foreign exchange contracts

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

Interest rate swaps

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

Other investments

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net and were not material for 2020 and 2019.

Derivative Fair Values

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

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
As at December 31, 2020				
Assets [(2)]				
Energy contracts subject to regulatory deferral	**–**	**38**	**–**	**38**
Energy contracts not subject to regulatory deferral	**–**	**6**	**–**	**6**
Foreign exchange contracts and total return swaps	**16**	**–**	**–**	**16**
Other investments	**126**	**–**	**–**	**126**
	142	**44**	**–**	**186**
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	**–**	**(94)**	**–**	**(94)**
Energy contracts not subject to regulatory deferral	**–**	**(12)**	**–**	**(12)**
	–	**(106)**	**–**	**(106)**
As at December 31, 2019				
Assets [(2)]				
Energy contracts subject to regulatory deferral	–	22	–	22
Energy contracts not subject to regulatory deferral	–	8	–	8
Foreign exchange contracts, interest rate and total return swaps	14	4	–	18
Other investments	121	–	–	121
	135	34	–	169
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	(1)	(138)	–	(139)
Energy contracts not subject to regulatory deferral	–	(12)	–	(12)
	(1)	(150)	–	(151)

(1) Under the hierarchy, fair value is determined using: (i) Level 1 – unadjusted quoted prices in active markets; (ii) Level 2 – other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 – unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.

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

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

Derivative Volumes

As at December 31	2020	2019
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**522**	628
Electricity power purchase contracts *(GWh)*	**2,781**	3,198
Gas swap contracts *(PJ)*	**156**	168
Gas supply contract premiums *(PJ)*	**203**	241
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,588**	1,855
Gas swap contracts *(PJ)*	**36**	43

[1] Energy contracts settle on various dates through 2029

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2020	2019	2018
Revenue	**8,935**	8,783	8,390
Net earnings	**1,389**	1,852	1,286
Common Equity Earnings	**1,209**	1,655	1,100
EPS: *($)*			
Basic	**2.60**	3.79	2.59
Diluted	**2.60**	3.78	2.59
Total assets	**55,481**	53,404	53,051
Long-term debt (excluding current portion)	**23,113**	21,501	23,159
Dividends declared: *($)*			
Per common share	**1.965**	1.855	1.750
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G [1]	**1.0983**	1.0983	1.0345
Series H [2]	**0.5003**	0.6250	0.6250
Series I [3]	**0.4987**	0.7771	0.7116
Series J	**1.1875**	1.1875	1.1875
Series K [4]	**0.9823**	0.9823	1.0000
Series M [5]	**0.9783**	1.0133	1.0250

[1] The annual dividend per share was reset to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.
[2] The annual dividend per share was reset to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.
[3] Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.
[4] The annual dividend per share was reset to $0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.
[5] The annual dividend per share was reset to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.

2020/2019

For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 19, "Operating Results" on page 23, and "Financial Position" on page 31.

2019/2018

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

The increase in Common Equity Earnings reflected the following significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion; and (ii) an $83 million favourable adjustment resulting from the November 2019 FERC decision at ITC, discussed above.

Excluding the significant one-time items, the increase in Common Equity Earnings was primarily due to Rate Base growth; lower operating expenses, primarily at FortisAlberta; and favourable foreign exchange. The increase was partially offset by the impact of weather in Belize and Arizona, higher costs associated with Rate Base growth not reflected in customer rates at UNS Energy, regulatory decisions at ITC, and lower realized margins at Aitken Creek. One-time positive tax adjustments, primarily recognized in 2018, also contributed to the increase in earnings, as discussed below.

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

The increase in EPS reflects the above-noted earnings increases, partially offset by a 12.1 million increase in the weighted average number of common shares outstanding associated with the Corporation's: (i) $1.2 billion common equity issuance in the fourth quarter of 2019; (ii) ATM Program; and (iii) DRIP and share purchase plan.

The increase in total assets was due to 2019 capital expenditures, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales

	2020	2019	Variance
Regulated utilities			
UNS Energy			
Retail Electricity *(GWh)*	**2,345**	2,223	122
Wholesale Electricity *(GWh)*	**1,871**	1,814	57
Gas *(PJ)*	**5**	5	–
Central Hudson			
Electricity *(GWh)*	**1,200**	1,188	12
Gas *(PJ)*	**7**	6	1
FortisBC Energy *(PJ)*	**67**	71	(4)
FortisAlberta *(GWh)*	**4,138**	4,279	(141)
FortisBC Electric *(GWh)*	**894**	888	6
Other Electric *(GWh)*	**2,362**	2,427	(65)
Non-regulated			
Energy Infrastructure *(GWh)*	**103**	14	89

The increase in electricity sales was driven by: (i) higher retail electricity sales at UNS Energy due to favourable weather; and (ii) increased hydroelectric production in Belize due to higher rainfall levels. The increase was tempered by lower average consumption by oil and gas and commercial customers at FortisAlberta, largely associated with the COVID-19 Pandemic and the downturn in the oil and gas sector.

Gas volumes were slightly lower than 2019 due to lower consumption by transportation customers at FortisBC Energy.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2020**	2019	Variance	**2020**	2019	Variance
Regulated utilities						
ITC	**419**	500	(81)	**109**	171	(62)
UNS Energy	**525**	510	15	**45**	38	7
Central Hudson	**242**	226	16	**35**	30	5
FortisBC Energy	**476**	428	48	**74**	77	(3)
FortisAlberta	**139**	150	(11)	**33**	33	–
FortisBC Electric	**117**	112	5	**13**	12	1
Other Electric	**381**	381	–	**32**	22	10
Non-regulated						
Energy Infrastructure	**47**	19	28	**27**	6	21
Corporate and Other	**–**	–	–	**(37)**	(43)	6
Total	**2,346**	2,326	20	**331**	346	(15)
Weighted average number of common shares outstanding *(millions)*				**465.8**	447.1	18.7
Basic EPS *($)*				**0.71**	0.77	(0.06)

The increase in revenue was driven by: (i) overall higher flow-through costs, mainly at FortisBC Energy; (ii) Rate Base growth; and (iii) the impact of favourable weather including higher retail sales in Arizona and hydroelectric production in Belize. The increase was partially offset by the $91 million favourable ROE adjustment recorded in the fourth quarter of 2019 by ITC associated with the November 2019 FERC decision (see "Regulatory Highlights" on page 29).

The decrease in Common Equity Earnings was due primarily to the implementation of the November 2019 FERC decision in the fourth quarter of 2019 including the reversal of prior period liabilities. This impact was partially offset by Rate Base growth, the favourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek, and higher hydroelectric production in Belize.

The decrease in basic EPS reflects lower Common Equity Earnings and an increase in the weighted average number of common shares outstanding associated with the Corporation's December 2019 common equity offering.

Cash Flows

($ millions)	**2020**	2019	Variance
Cash, beginning of period	**494**	228	266
Cash from (used in):			
Operating activities	**700**	634	66
Investing activities	**(1,235)**	(1,104)	(131)
Financing activities	**308**	627	(319)
Foreign exchange	**(18)**	(15)	(3)
Cash, end of period	**249**	370	(121)

Operating Activities

The variance largely reflects the upfront payment received by FortisAlberta in the fourth quarter of 2020 associated with a long-term energy retailer agreement. An increase in Operating Cash Flow associated with higher energy sales was largely offset by the timing of the recovery of flow-through costs and slower collections from customers associated with the COVID-19 Pandemic.

Investing Activities

The variance reflects higher capital expenditures in accordance with the Corporation's capital plan.

Financing Activities

See "Cash Flow Summary" on page 33.

SUMMARY OF QUARTERLY RESULTS

Quarter Ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2020	**2,346**	**331**	**0.71**	**0.71**
September 30, 2020	**2,121**	**292**	**0.63**	**0.63**
June 30, 2020	**2,077**	**274**	**0.59**	**0.59**
March 31, 2020	**2,391**	**312**	**0.67**	**0.67**
December 31, 2019	2,326	346	0.77	0.77
September 30, 2019	2,051	278	0.64	0.63
June 30, 2019	1,970	720	1.66	1.66
March 31, 2019	2,436	311	0.72	0.72

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

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

December 2020/December 2019

See "Fourth Quarter Results" on page 52.

September 2020/September 2019

Common Equity Earnings increased by $14 million due mainly to: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates; and (ii) lower contributions from ITC, due to the timing of earnings associated with the FERC ROE decisions, and a lower effective tax rate in 2019. The $0.01 decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019, partially offset by the above noted factors.

June 2020/June 2019

Common Equity Earnings decreased by $446 million and basic EPS decreased by $1.07. Earnings for the quarter reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the reversal of a $13 million tax recovery, originally recognized in 2019, due to the finalization in April 2020 of anti-hybrid regulations associated with US tax reform, partially offset by; (iii) a $27 million favourable base ROE adjustment at ITC as a result of the May 2020 FERC decision reflecting the reversal of liabilities accrued in prior years. Notwithstanding the significant one-time items, the regulated utilities delivered improved financial results reflecting: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; (iii) favourable foreign exchange; and (iv) timing of operating expenses at FortisBC Energy. This growth was tempered by lower sales in the Caribbean due to a decline in tourism-related activities and higher COVID-related expenses, driven by Central Hudson.

March 2020/March 2019

Common Equity Earnings were comparable with 2019. Rate Base growth, lower non-recoverable operating expenses at ITC, and lower expenses in the Corporate and Other segment were tempered by: (i) higher costs associated with Rate Base growth at UNS Energy not yet reflected in rates; (ii) financial market volatility that caused a decline in the market value of certain investments that support retirement benefits at UNS Energy; and (iii) unrealized losses on foreign exchange contracts in the Corporate and Other segment. The decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2020 or 2019. Inter-company balances, transactions and profit between non-regulated and regulated entities are not eliminated on consolidation. These related-party transactions include: (i) the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy; and (ii) the sale of capacity by the Waneta Expansion to FortisBC Electric up to the April 16, 2019 disposition of the Waneta Expansion. These transactions, which are not eliminated on consolidation, did not have a material impact on consolidated earnings, financial position or cash flows.

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

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

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities laws. As of December 31, 2020, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and US securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2020.

Internal Controls over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2020, based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2020, the Corporation's ICFR was effective.

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

OUTLOOK

The Corporation maintains its positive long-term outlook. Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories. While uncertainty exists due to the COVID-19 Pandemic, the Corporation does not currently expect it to have a material financial impact in 2021.

The Corporation's $19.6 billion five-year capital plan is expected to increase Rate Base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, translating into three- and five-year CAGRs of approximately 6.5% and 6.0%, respectively. Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects long-term growth in Rate Base will support earnings and dividend growth. Fortis is targeting average annual dividend growth of approximately 6% through 2025. This dividend growth guidance is premised on the assumptions listed under "Forward-Looking Information" on page 56, including no material impact from the COVID-19 Pandemic, the expectation of reasonable outcomes for regulatory proceedings, and the successful execution of the five-year capital plan.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the expectation that the COVID-19 Pandemic will not have a material financial impact in 2021 and will not impact the five-year capital plan; targeted average annual dividend growth through 2025; forecast capital expenditures for 2021–2025 and expected funding sources; forecast Rate Base and Rate Base growth for 2023 and 2025; the expectation that long-term growth in Rate Base will support earnings and dividend growth; the expectation that Fortis will remain at the forefront of the industry and is well positioned to capitalize on evolving industry opportunities; expected timing, outcome and impact of regulatory decisions; expected or potential funding sources for operating expenses, interest costs and capital plans; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have access to long-term capital and will remain compliant with debt covenants in 2021; the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Oso Grande Wind Project, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Resiliency Tank, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan, including the Lake Erie Connector Project; and the expectation that the adoption of future accounting pronouncements will not have a Material Adverse Impact.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information including, without limitation: no material impact from the COVID-19 Pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the five-year capital plan; no material capital project or financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability or upset; the continued ability to maintain the performance of the electricity and gas systems; no severe and prolonged economic downturn; sufficient liquidity and capital resources; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; the continued availability of natural gas, fuel, coal and electricity supply; continuation of power supply and capacity purchase contracts; no significant changes in government energy plans, environmental laws and regulations that could have a material negative impact; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no significant changes in tax laws and the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; and favourable labour relations.

Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from those discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risks" in this MD&A and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2021 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change, physical risks and service disruption; the impact of pandemics and public health crises, including the COVID-19 Pandemic; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; and the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation.

All forward-looking information herein is given as of February 11, 2021. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

GLOSSARY

2020 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2020

ACC: Arizona Corporation Commission

ACCP: AESO customer contribution policy

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

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

Adjusted Common Equity Earnings: net earnings attributable to common equity shareholders adjusted as shown under "Non-US GAAP Financial Measures" on page 28

Adjusted Payout Ratio: dividends per common share divided by Adjusted Basic EPS as shown under "Non-US GAAP Financial Measures" on page 28

AESO: Alberta Electric System Operator

AFUDC: allowance for funds used during construction

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

AMI: Advanced Metering Infrastructure

ASU: Accounting Standards Update

ATM Program: at-the-market common equity program

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

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

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

CAGR(s): compound average growth rate of a particular item. CAGR = $(EV/BV)^{1-N}$–1, where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) N is the number of periods. Calculated on a constant US dollar to Canadian dollar exchange rate

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2020) subsidiary of Fortis, together with its subsidiary

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

CEO: Chief Executive Officer of Fortis

CFO: Chief Financial Officer of Fortis

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS Regulation: cost of service regulation

COVID-19 Pandemic: declared by the World Health Organization in March 2020 as a result of a novel coronavirus

CPCN: Certificate of Public Convenience and Necessity

DBRS Morningstar: DBRS Limited

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPS: earnings per common share

ERM: enterprise risk management

FERC: Federal Energy Regulatory Commission

Fortis: Fortis Inc.

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

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

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

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

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

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

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

GCOC: generic cost of capital

GHG: greenhouse gas

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

GWh: gigawatt hour(s)

ICFR: internal controls over financial reporting

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

LIBOR: London Interbank Offered Rate

LNG: liquefied natural gas

Luna: Luna Energy Facility

kV: kilovolt

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

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

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

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2020

MISO: Midcontinent Independent System Operator, Inc.

MRP: Multi-Year Rate Plan

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

MW: megawatt(s)

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

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

NOPR: notice of proposed rulemaking

NYSE: New York Stock Exchange

OEB: Ontario Energy Board

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

PPA: power purchase agreement

PSC: New York State Public Service Commission

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

RICE Units: natural gas reciprocating internal combustion engine units

ROA: rate of return on Rate Base

ROE: rate of return on common equity

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

San Juan: San Juan Generating Station Unit 1

SEDAR: Canadian System for Electronic Document Analysis and Retrieval

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

TFO: transmission facility owners

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

TSX: Toronto Stock Exchange

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

US: United States of America

US GAAP: accounting principles generally accepted in the US

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

Wataynikaneyap Partnership: Wataynikaneyap Power Limited Partnership

Financials

Table of Contents

Management's Report on Internal Control over Financial Reporting 59

Report of Independent Registered Public Accounting Firm – Opinion on the Financial Statements 60

Report of Independent Registered Public Accounting Firm – Opinion on Internal Control over Financial Reporting 62

Consolidated Balance Sheets 63

Consolidated Statements of Earnings 64

Consolidated Statements of Comprehensive Income 64

Consolidated Statements of Cash Flows 65

Consolidated Statements of Changes in Equity 66

Notes to Consolidated Financial Statements

NOTE 1 Description of Business 67

NOTE 2 Regulation 68

NOTE 3 Summary of Significant Accounting Policies 72

NOTE 4 Segmented Information 78

NOTE 5 Revenue 80

NOTE 6 Accounts Receivable and Other Current Assets 81

NOTE 7 Inventories 81

NOTE 8 Regulatory Assets and Liabilities 82

NOTE 9 Other Assets 84

NOTE 10 Property, Plant and Equipment 84

NOTE 11 Intangible Assets 86

NOTE 12 Goodwill 86

NOTE 13 Accounts Payable and Other Current Liabilities 86

NOTE 14 Long-Term Debt 87

NOTE 15 Leases 90

NOTE 16 Other Liabilities 92

NOTE 17 Common Shares 92

NOTE 18 Earnings Per Common Share 92

NOTE 19 Preference Shares 93

NOTE 20 Accumulated Other Comprehensive Income 94

NOTE 21 Stock-Based Compensation Plans 95

NOTE 22 Disposition 97

NOTE 23 Other Income, Net 97

NOTE 24 Income Taxes 98

NOTE 25 Employee Future Benefits 100

NOTE 26 Supplementary Cash Flow Information 104

NOTE 27 Fair Value of Financial Instruments and Risk Management 104

NOTE 28 Commitments and Contingencies 108

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2020, based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2020, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2020 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2020. Deloitte LLP issued an unqualified opinion for both audits.

February 11, 2021

David G. Hutchens
President and Chief Executive Officer, Fortis Inc.

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

St. John's, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2020 and 2019, the related consolidated statements of earnings, comprehensive income, cash flows and changes in equity for each of the two years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Corporation's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2021, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Assessment for Impairment of Goodwill – Refer to Notes 3 and 12 to the financial statements

Critical Audit Matter Description

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

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

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the growth rate and discount rate used by management to estimate the fair value of more recently acquired reporting units included the following:

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

Impact of Rate Regulation on the financial statements – Refer to Notes 2, 3 and 8 to the financial statements

Critical Audit Matter Description

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

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

How the Critical Audit Matter was Addressed in the Audit

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

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information to evaluate the likelihood of recovery in future rates or of a future reduction in rates and the ability to earn a reasonable ROA or ROE.
- For regulatory matters in progress, inspecting the regulated utilities' filings for any evidence that might contradict management's assertions. We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 11, 2021

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2020, of the Corporation and our report dated February 11, 2021, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 11, 2021

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2020**	2019
ASSETS		
Current assets		
Cash and cash equivalents	**$ 249**	$ 370
Accounts receivable and other current assets *(Note 6)*	**1,369**	1,297
Prepaid expenses	**102**	88
Inventories *(Note 7)*	**422**	394
Regulatory assets *(Note 8)*	**470**	425
Total current assets	**2,612**	2,574
Other assets *(Note 9)*	**670**	620
Regulatory assets *(Note 8)*	**3,118**	2,958
Property, plant and equipment, net *(Note 10)*	**35,998**	33,988
Intangible assets, net *(Note 11)*	**1,291**	1,260
Goodwill *(Note 12)*	**11,792**	12,004
Total assets	**$ 55,481**	$ 53,404
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings *(Note 14)*	**$ 132**	$ 512
Accounts payable and other current liabilities *(Note 13)*	**2,321**	2,402
Regulatory liabilities *(Note 8)*	**441**	572
Current installments of long-term debt *(Note 14)*	**1,254**	690
Total current liabilities	**4,148**	4,176
Other liabilities *(Note 16)*	**1,599**	1,446
Regulatory liabilities *(Note 8)*	**2,662**	2,786
Deferred income taxes *(Note 24)*	**3,344**	2,969
Long-term debt *(Note 14)*	**23,113**	21,501
Finance leases *(Note 15)*	**331**	413
Total liabilities	**35,197**	33,291
Commitments and contingencies *(Note 28)*		
Equity		
Common shares *(Note 17)* [(1)]	**13,819**	13,645
Preference shares *(Note 19)*	**1,623**	1,623
Additional paid-in capital	**11**	11
Accumulated other comprehensive income *(Note 20)*	**34**	336
Retained earnings	**3,210**	2,916
Shareholders' equity	**18,697**	18,531
Non-controlling interests	**1,587**	1,582
Total equity	**20,284**	20,113
Total liabilities and equity	**$ 55,481**	$ 53,404

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

Approved on Behalf of the Board

See accompanying Notes to Consolidated Financial Statements

Douglas J. Haughey, Director

Tracey C. Ball, Director

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2020**	2019
Revenue *(Note 5)*	**$ 8,935**	$ 8,783
Expenses		
Energy supply costs	**2,562**	2,520
Operating expenses	**2,437**	2,452
Depreciation and amortization	**1,428**	1,350
Total expenses	**6,427**	6,322
Gain on disposition *(Note 22)*	**–**	577
Operating income	**2,508**	3,038
Other income, net *(Note 23)*	**154**	138
Finance charges	**1,042**	1,035
Earnings before income tax expense	**1,620**	2,141
Income tax expense *(Note 24)*	**231**	289
Net earnings	**$ 1,389**	$ 1,852
Net earnings attributable to:		
Non-controlling interests	**$ 115**	$ 130
Preference equity shareholders	**65**	67
Common equity shareholders	**1,209**	1,655
	$ 1,389	$ 1,852
Earnings per common share *(Note 18)*		
Basic	**$ 2.60**	$ 3.79
Diluted	**$ 2.60**	$ 3.78

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2020**	2019
Net earnings	**$ 1,389**	$ 1,852
Other comprehensive loss		
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $3 million and $13 million, respectively	**(311)**	(660)
Other, net of income tax recovery of $9 million and $5 million, respectively	**(27)**	(7)
	(338)	(667)
Comprehensive income	**$ 1,051**	$ 1,185
Comprehensive income attributable to:		
Non-controlling interests	**$ 79**	$ 55
Preference equity shareholders	**65**	67
Common equity shareholders	**907**	1,063
	$ 1,051	$ 1,185

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2020**	2019
Operating activities		
Net earnings	**$ 1,389**	$ 1,852
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – property, plant and equipment	**1,282**	1,199
Amortization – intangible assets	**131**	125
Amortization – other	**15**	26
Deferred income tax expense *(Note 24)*	**226**	247
Equity component, allowance for funds used during construction *(Note 23)*	**(78)**	(74)
Gain on disposition *(Note 22)*	**–**	(583)
Other	**165**	145
Change in long-term regulatory assets and liabilities	**5**	(106)
Change in working capital *(Note 26)*	**(434)**	(168)
Cash from operating activities	**2,701**	2,663
Investing activities		
Capital expenditures – property, plant and equipment	**(3,857)**	(3,499)
Capital expenditures – intangible assets	**(182)**	(221)
Contributions in aid of construction	**68**	102
Proceeds on disposition *(Note 22)*	**–**	995
Other	**(161)**	(145)
Cash used in investing activities	**(4,132)**	(2,768)
Financing activities		
Proceeds from long-term debt, net of issuance costs *(Note 14)*	**3,470**	937
Repayments of long-term debt, net of extinguishment costs, and finance leases	**(1,251)**	(1,676)
Borrowings under committed credit facilities	**5,648**	5,892
Repayments under committed credit facilities	**(5,299)**	(6,290)
Net change in short-term borrowings	**(413)**	472
Issue of common shares, net of costs, and dividends reinvested *(Note 17)*	**58**	1,442
Dividends		
Common shares, net of dividends reinvested	**(786)**	(494)
Preference shares	**(65)**	(67)
Subsidiary dividends paid to non-controlling interests	**(65)**	(73)
Other	**30**	11
Cash from financing activities	**1,327**	154
Effect of exchange rate changes on cash and cash equivalents	**(17)**	(26)
Change in cash and cash equivalents	**(121)**	23
Cash and change in cash associated with assets held for sale	**–**	15
Cash and cash equivalents, beginning of year	**370**	332
Cash and cash equivalents, end of year	**$ 249**	$ 370

Supplementary Cash Flow Information *(Note 26)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2020 and 2019 *(in millions of Canadian dollars, except share numbers)*	**Common Shares** *(# millions)*	**Common Shares** *(Note 17)*	**Preference Shares** *(Note 19)*	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** *(Note 20)*	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2019	**463.3**	**$ 13,645**	**$ 1,623**	**$ 11**	**$ 336**	**$ 2,916**	**$ 1,582**	**$ 20,113**
Net earnings	**–**	**–**	**–**	**–**	**–**	**1,274**	**115**	**1,389**
Other comprehensive loss	**–**	**–**	**–**	**–**	**(302)**	**–**	**(36)**	**(338)**
Common shares issued	**3.5**	**174**	**–**	**(3)**	**–**	**–**	**–**	**171**
Advances to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(13)**	**(13)**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(65)**	**(65)**
Dividends declared on common shares ($1.965 per share)	**–**	**–**	**–**	**–**	**–**	**(915)**	**–**	**(915)**
Dividends on preference shares	**–**	**–**	**–**	**–**	**–**	**(65)**	**–**	**(65)**
Other	**–**	**–**	**–**	**3**	**–**	**–**	**4**	**7**
As at December 31, 2020	**466.8**	**$ 13,819**	**$ 1,623**	**$ 11**	**$ 34**	**$ 3,210**	**$ 1,587**	**$ 20,284**
As at December 31, 2018	428.5	$ 11,889	$ 1,623	$ 11	$ 928	$ 2,082	$ 1,923	$ 18,456
Net earnings	–	–	–	–	–	1,722	130	1,852
Other comprehensive loss	–	–	–	–	(592)	–	(75)	(667)
Common shares issued	34.8	1,756	–	(5)	–	–	–	1,751
Advances to non-controlling interests	–	–	–	–	–	–	(8)	(8)
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	–	(73)	(73)
Dividends declared on common shares ($1.855 per share)	–	–	–	–	–	(821)	–	(821)
Dividends on preference shares	–	–	–	–	–	(67)	–	(67)
Disposition *(Note 22)*	–	–	–	–	–	–	(318)	(318)
Other	–	–	–	5	–	–	3	8
As at December 31, 2019	463.3	$ 13,645	$ 1,623	$ 11	$ 336	$ 2,916	$ 1,582	$ 20,113

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

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

Regulated Utilities

ITC

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

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

UNS Energy

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

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,233 megawatts ("MW"), including 54 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

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

Central Hudson

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

FortisBC Energy

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

FortisAlberta

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

FortisBC Electric

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

Other Electric

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

For the years ended December 31, 2020 and 2019

1. DESCRIPTION OF BUSINESS (cont'd)

Regulated Utilities (cont'd)

Other Electric (cont'd)

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 143 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 130 MW. FortisOntario consists of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 5 MW. Wataynikaneyap Partnership is a partnership between 24 First Nations communities, Fortis and Algonquin Power & Utilities Corp. with a mandate to connect remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

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

Non-Regulated

Energy Infrastructure

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

Corporate and Other

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

2. REGULATION

General

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

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

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

The Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

Nature of Regulation

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

(1) ROA for Caribbean Utilities and FortisTCI

(2) Includes the allowed common equity and base ROE plus incentive adders for ITCTransmission, METC, and ITC Midwest

(3) Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator ("MISO") region of 10.77%, up from 10.63% as set in the November 2019 decision. See "Significant Regulatory Developments" below

(4) Annual true-up reflected in rates within a two-year period

(5) Effective January 1, 2021, 53% allowed common equity and 9.15% ROE with 0.20% return on the fair value increment. See "COVID-19 Pandemic Impacts – Delayed and Postponed Regulatory Proceedings" below

(6) Approved effective August 1, 2019, subject to refund following hearing and settlement procedures. As at December 31, 2020, $19 million (2019 – $5 million) has been reserved as a regulatory liability

(7) Pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect a capital structure of 48%, 49% and 50% common equity as of July 1, 2018, 2019 and 2020, respectively. See "COVID-19 Pandemic Impacts – Delayed and Postponed Regulatory Proceedings" below

(8) Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below

(9) FortisAlberta is subject to PBR including mechanisms for flow-through costs and capital expenditures not otherwise recovered through customer rates. FortisAlberta's current PBR term expires as of December 31, 2022

(10) Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033

(11) Operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039

(12) Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037

2. *REGULATION (cont'd)*

COVID-19 Pandemic Impacts

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

Customer Relief Initiatives

UNS Energy

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

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

Central Hudson

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

FortisBC Energy and FortisBC Electric

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

Delayed and Postponed Regulatory Proceedings

UNS Energy

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

Central Hudson

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

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

FortisAlberta

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

Other Electric

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

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

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

Significant Regulatory Developments

ITC

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

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

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

Central Hudson

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

FortisBC Energy and FortisBC Electric

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

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

FortisAlberta

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

In November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

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

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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

These consolidated financial statements include the accounts of the Corporation and its subsidiaries, and a controlled variable interest entity up to the date of its disposition on April 16, 2019 (Note 22). They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with US GAAP for rate-regulated entities.

Cash and Cash Equivalents

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

Allowance for Credit Losses

Fortis and its subsidiaries recognize an allowance for credit losses (2019 – allowance for doubtful accounts) to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

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

Regulatory Assets and Liabilities

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

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

Investments

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

Property, Plant and Equipment

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

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual asset removal costs are netted when incurred.

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

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2020 totalled $41 million (2019 – $40 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 23). Both components are charged to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta the cost of PPE includes required contributions to AESO toward funding the construction of transmission facilities.

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

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

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2020 ranged from 0.9% to 39.8% (2019 – 0.9% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.5% for 2020 (2019 – 2.6%).

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

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

Intangible Assets

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

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

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 33.0% for 2020 (2019 – 1.0% to 33.0%).

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

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

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

Impairment of Long-Lived Assets

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

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

Goodwill

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

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

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

Deferred Financing Costs

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

Employee Future Benefits

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

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

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

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

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

For most of the Corporation's regulated utilities, any difference between defined benefit pension or OPEB plan costs ordinarily recognized under US GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (Note 8).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8).

Leases

A right-of-use asset and lease liability is recognized for all leases with a lease term greater than 12 months. The right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

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

Revenue Recognition

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

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

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

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

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

Revenue excludes sales and municipal taxes collected from customers.

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

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Stock-Based Compensation

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

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

Fortis recognizes liabilities associated with its directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans. DSUs, PSUs and RSUs issued pre-2020 represent cash-settled awards and RSUs issued in 2020 represent cash or share-settled awards, depending on settlement elections and share ownership requirements of the executive. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2020 was $52.36 (2019 – $53.97). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

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

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2020 was US$1.00=CA$1.27 (2019 – US$1.00=CA$1.30).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CA$1.34 for 2020 (2019 – US$1.00=CA$1.33).

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

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

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

Derivatives and Hedging

Derivatives Not Designated as Hedges

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

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8).

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

Derivatives Designated as Hedges

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

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

Presentation of Derivatives

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

Income Taxes

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

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

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

Differences between the income tax expense or recovery recognized under US GAAP and reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 8).

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

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $3.4 billion as at December 31, 2020 (2019 – $2.8 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

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

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

Asset Retirement Obligations

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

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 16) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Accretion and depreciation expense are deferred as a regulatory asset or liability based on regulatory recovery of these costs. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

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

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

New Accounting Policies

Financial Instruments

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

Use of Accounting Estimates

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

Future Accounting Pronouncements

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

For the years ended December 31, 2020 and 2019

4. SEGMENTED INFORMATION

General

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

Related-Party and Inter-Company Transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2020 or 2019.

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

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

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

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

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

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

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

5. REVENUE

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

(1) Includes $227 million and $273 million from regulated operations for 2020 and 2019, respectively

(2) Includes a $40 million and $91 million base ROE adjustment associated with the May 2020 and November 2019 FERC decisions, respectively (Notes 2 and 8)

Revenue from Contracts with Customers

Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates including the flow through of commodity costs.

Other services revenue includes: (i) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (ii) revenue from storage optimization activities at Aitken Creek; and (iii) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

Alternative Revenue

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

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period (Note 8). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

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

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

Other Revenue

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

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

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

[1] Allowance for doubtful accounts for 2019

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

Allowance for Credit Losses

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

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

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

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

7. INVENTORIES

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

For the years ended December 31, 2020 and 2019

8. REGULATORY ASSETS AND LIABILITIES

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

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

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

Related accounts include the annual true-up mechanism at ITC (Note 5).

(3) *Deferred Lease Costs*
Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 15). The depreciation of the asset under finance lease and interest expense on the finance lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under the BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(4) *Generation Early Retirement Costs*

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

(5) *Other Regulatory Assets and Liabilities*

Comprised of regulatory assets and liabilities individually less than $40 million.

(6) *Renewable Energy Surcharge*

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

The ACC measures RES compliance through Renewable Energy Credits ("RECs"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 9) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are utilized for RES compliance, energy supply costs and revenue are recognized in an equal amount.

(7) *Energy Efficiency Liability*

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

(8) *Electric and Gas Moderator Account*

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

Regulatory assets not earning a return: (i) totalled $1,678 million and $1,510 million as at December 31, 2020 and 2019, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

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

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

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through trust-owned life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 27).

10. PROPERTY, PLANT AND EQUIPMENT

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2020			
Distribution			
Electric	**$ 11,921**	**$ (3,223)**	**$ 8,698**
Gas	**5,546**	**(1,422)**	**4,124**
Transmission			
Electric	**15,888**	**(3,413)**	**12,475**
Gas	**2,360**	**(719)**	**1,641**
Generation	**6,441**	**(2,550)**	**3,891**
Other	**4,178**	**(1,347)**	**2,831**
Assets under construction	**2,012**	**–**	**2,012**
Land	**326**	**–**	**326**
	$ 48,672	**$ (12,674)**	**$ 35,998**
2019			
Distribution			
Electric	$ 11,396	$ (3,125)	$ 8,271
Gas	5,277	(1,330)	3,947
Transmission			
Electric	15,207	(3,293)	11,914
Gas	2,267	(681)	1,586
Generation	6,380	(2,472)	3,908
Other	4,042	(1,327)	2,715
Assets under construction	1,329	–	1,329
Land	318	–	318
	$ 46,216	$ (12,228)	$ 33,988

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

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

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

Other assets include buildings, equipment, vehicles, inventory, information technology assets and Aitken Creek.

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

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

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2020, interests in jointly owned facilities consisted of the following.

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

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

For the years ended December 31, 2020 and 2019

11. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2020			
Computer software	**$ 932**	**$ (524)**	**$ 408**
Land, transmission and water rights	**898**	**(142)**	**756**
Other	**114**	**(64)**	**50**
Assets under construction	**77**	**–**	**77**
	$ 2,021	**$ (730)**	**$ 1,291**
2019			
Computer software	$ 946	$ (576)	$ 370
Land, transmission and water rights	890	(122)	768
Other	115	(61)	54
Assets under construction	68	–	68
	$ 2,019	$ (759)	$ 1,260

Included in the cost of land, transmission and water rights as at December 31, 2020 was $136 million (2019 – $133 million) not subject to amortization. Amortization expense was $131 million for 2020 (2019 – $125 million). Amortization is estimated to average approximately $81 million for each of the next five years.

12. GOODWILL

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

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

No goodwill impairment was recognized by the Corporation in 2020 or 2019.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

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

14. LONG-TERM DEBT

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

For the years ended December 31, 2020 and 2019

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 dividends or any other restricted payments if, immediately thereafter, its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances

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

(1) Floating rate of a one-month LIBOR plus a spread of 0.45%

(2) Repay credit facility borrowings

(3) General corporate purposes

(4) Maximum amount of borrowings under this agreement of US$400 million has been drawn; current period borrowings were used to repay an outstanding commercial paper balance.

(5) Floating rate of a two-month LIBOR plus a spread of 0.60%

(6) Early redemption of unsecured term loan borrowing of US$400 million

(7) Finance capital expenditures

(8) Repay maturing long-term debt

Long-Term Debt Repayments

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

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

In December 2020 Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $2.0 billion. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Credit Facilities

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

(1) The weighted average interest rate was approximately 0.8% (2019 – 3.2%).

(2) The weighted average interest rate was approximately 0.9% (2019 – 2.4%). The current portion was $651 million (2019 – $252 million).

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

For the years ended December 31, 2020 and 2019

14. LONG-TERM DEBT (cont'd)

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

(in millions)	Amount ($)	Maturity
Unsecured committed revolving credit facilities		
Regulated utilities		
ITC [(1)]	**US 900**	October 2023
UNS Energy	**US 500**	October 2022
Central Hudson	**US 200**	March 2025
FortisBC Energy	**700**	August 2024
FortisAlberta	**250**	August 2024
FortisBC Electric	**150**	April 2024
Other Electric	**190**	[(2)]
Other Electric	**US 70**	January 2025
Corporate and Other	**1,850**	[(3)]
Other facilities		
Regulated utilities		
Central Hudson – uncommitted credit facility	**US 30**	n/a
FortisBC Energy – uncommitted credit facility	**55**	March 2022
FortisBC Electric – unsecured demand overdraft facility	**10**	n/a
Other Electric – unsecured demand facilities	**20**	n/a
Other Electric – unsecured demand facility and emergency standby loan	**US 60**	June 2021
Corporate and Other – unsecured non-revolving facility	**30**	n/a

(1) ITC also has a US$400 million commercial paper program, under which US$67 million was outstanding as at December 31, 2020, as reported in short-term borrowings.

(2) $40 million in June 2021, $50 million in February 2022 and $100 million in August 2024

(3) $500 million in April 2021, $50 million in April 2022 and $1.3 billion in July 2024

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 21 years, with optional renewal terms. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the leased premises.

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

Leases were presented on the consolidated balance sheets as follows.

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

(1) FortisBC Electric has a finance lease for the BPPA (Note 8), which relates to the sale of the output of the Brilliant hydroelectric plant, and for the Brilliant Terminal Station ("BTS"), which relates to the use of the station. Both agreements expire in 2056. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which includes the original and ongoing capital cost, and related variable power purchase costs. The BTS requires semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs.

(2) In December 2020 TEP purchased a 32.2% undivided interest in the Springerville Common Facilities, which had previously been leased (Note 10).

The components of lease expense were as follows.

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

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

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

Supplemental lease information was as follows.

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

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

16. OTHER LIABILITIES

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

(1) Environmental regulations require Central Hudson to investigate sites at which it or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. As at December 31, 2020, an obligation of $96 million was recognized, including a current portion of $27 million recognized in accounts payable and other current liabilities (Note 13). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 8).

(2) TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $61 million upon expiry of the coal agreements between 2022 and 2031. The present value of the estimated future liability is shown in the table above.

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

17. COMMON SHARES

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

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

18. EARNINGS PER COMMON SHARE

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

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

19. PREFERENCE SHARES

Authorized

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

Issued and Outstanding	2020		2019	
First Preference Shares	Number of Shares (in thousands)	Amount (in millions)	Number of Shares (in thousands)	Amount (in millions)
Series F	**5,000**	**$ 122**	5,000	$ 122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,025	172
Series I	**2,335**	**57**	2,975	73
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**$ 1,623**	66,200	$ 1,623

Characteristics of the first preference shares are as follows.

First Preference Shares [(1) (2)]	Initial Yield (%)	Annual Dividend ($)	Reset Dividend Yield (%)	Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a One-For-One Basis
Perpetual fixed rate						
Series F	4.90	1.2250	–	Currently Redeemable	25.00	–
Series J [(3)]	4.75	1.1875	–	Currently Redeemable	25.25	–
Fixed rate reset [(4) (5)]						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	–
Series H [(6)]	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating rate reset [(5) (7)]						
Series I	2.10	–	1.45	June 1, 2025	25.00	Series H
Series L	–	–	–	–	–	Series K
Series N	–	–	–	–	–	Series M

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

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

(3) First Preference Shares, Series J are redeemable as of December 1, 2021 and thereafter at $25.00 per share.

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

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

(6) The annual dividend per share for the First Preference Shares, Series H was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.

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

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

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

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	Opening Balance	Net Change	Ending Balance
2020			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**$ 713**	**$ (336)**	**$ 377**
Hedges of net investments in foreign operations	**(359)**	**60**	**(299)**
Income tax expense	**(3)**	**(3)**	**(6)**
	351	**(279)**	**72**
Other			
Cash flow hedges *(Note 27)*	**17**	**(21)**	**(4)**
Unrealized employee future benefits losses *(Note 25)*	**(38)**	**(11)**	**(49)**
Income tax recovery	**6**	**9**	**15**
	(15)	**(23)**	**(38)**
Accumulated other comprehensive income	**$ 336**	**$ (302)**	**$ 34**
2019			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	$ 1,470	$ (757)	$ 713
Hedges of net investments in foreign operations	(544)	185	(359)
Income tax recovery (expense)	10	(13)	(3)
	936	(585)	351
Other			
Cash flow hedges *(Note 27)*	11	6	17
Unrealized employee future benefits losses *(Note 25)*	(20)	(18)	(38)
Income tax recovery	1	5	6
	(8)	(7)	(15)
Accumulated other comprehensive income	$ 928	$ (592)	$ 336

21. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options are exercisable for a period of 10 years from the grant date, expire no later 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.

The following options were granted in 2020 and 2019.

	2020	2019
Options granted *(in thousands)*	**686**	852
Exercise price *($)* [(1)]	**58.40**	47.57
Grant date fair value *($)*	**4.20**	3.70
Valuation assumptions:		
Dividend yield *(%)* [(2)]	**3.7**	3.8
Expected volatility *(%)* [(3)]	**15.8**	15.2
Risk-free interest rate *(%)* [(4)]	**1.2**	1.8
Weighted average expected life *(years)* [(5)]	**5.2**	5.6

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

The following table summarizes information related to stock options for 2020.

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

(1) As at December 31, 2020, there was $7 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
(2) As at December 31, 2020, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $19 million.

The following table summarizes additional stock option information.

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

21. *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.

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

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

PSU Plans

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

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

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

The following table summarizes information related to PSUs.

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

(1) Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years

(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)

(3) Relates to outstanding PSUs and reflects a weighted average contractual life of one year

RSU Plans

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

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash or, beginning with the 2020 grant, common shares of the Corporation. RSUs issued in 2020 may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executive's settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

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

(1) Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years

(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)

(3) Relates to outstanding RSUs and reflects a weighted average contractual life of one year

22. DISPOSITION

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

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

23. OTHER INCOME, NET

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

For the years ended December 31, 2020 and 2019

24. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

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

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

Unrecognized Tax Benefits

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

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2020. Fortis has not recognized interest expense in 2020 and 2019 related to unrecognized tax benefits.

Income Tax Expense

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

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

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

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

Income Tax Carryforwards

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

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2013 to 2020 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2020 taxation years are still open for audit in United States jurisdictions.

25. EMPLOYEE FUTURE BENEFITS

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

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2017 for the Corporation; December 31, 2018 for FortisBC Energy and FortisBC Electric (plan covering unionized employees); December 31, 2019 for the remaining FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; and December 31, 2020 for Caribbean Utilities.

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

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

Allocation of Plan Assets

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

Fair Value of Plan Assets

(in millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
2020				
Equities	**$ 713**	**$ 1,163**	**$ –**	**$ 1,876**
Fixed income	**197**	**1,580**	**–**	**1,777**
Real estate	**–**	**17**	**204**	**221**
Private equities	**–**	**–**	**20**	**20**
Cash and other	**8**	**17**	**–**	**25**
	$ 918	**$ 2,777**	**$ 224**	**$ 3,919**
2019				
Equities	$ 622	$ 1,050	$ –	$ 1,672
Fixed income	171	1,445	–	1,616
Real estate	–	16	207	223
Private equities	–	–	22	22
Cash and other	8	10	–	18
	$ 801	$ 2,521	$ 229	$ 3,551

(1) See Note 27 for a description of the fair value hierarchy.

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

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

Funded Status

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

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

(2) The accumulated benefit obligation, which excludes assumptions about future salary levels, for defined benefit pension plans was $3,679 million as at December 31, 2020 (2019 – $3,352 million).

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

(4) The increases in the defined benefit pension and OPEB plan assets were driven by market returns.

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

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

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

For the years ended December 31, 2020 and 2019

25. EMPLOYEE FUTURE BENEFITS (cont'd)

Net Benefit Cost [1]

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

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

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

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2020**	2019	**2020**	2019
Unamortized net actuarial losses (gains)	**$ 42**	$ 32	**$ (1)**	$ (2)
Unamortized past service costs	**1**	1	**7**	7
Income tax recovery	**(10)**	(8)	**(1)**	(1)
Accumulated other comprehensive income	**$ 33**	$ 25	**$ 5**	$ 4
Net actuarial losses (gains)	**$ 517**	$ 486	**$ 12**	$ (18)
Past service credits	**(7)**	(9)	**(8)**	(8)
Other regulatory deferrals	**13**	15	**18**	19
	$ 523	$ 492	**$ 22**	$ (7)
Regulatory assets *(Note 8)*	**$ 523**	$ 492	**$ 65**	$ 38
Regulatory liabilities *(Note 8)*	**–**	–	**(43)**	(45)
Net regulatory assets (liabilities)	**$ 523**	$ 492	**$ 22**	$ (7)

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

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

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

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

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

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

Expected Benefit Payments

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

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

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

For the years ended December 31, 2020 and 2019

26. SUPPLEMENTARY CASH FLOW INFORMATION

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

27. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

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

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

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

Energy Contracts Subject to Regulatory Deferral

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

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2020, unrealized losses of $73 million (2019 – $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 – $2 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

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

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

Total Return Swaps

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

Foreign Exchange Contracts

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

Interest Rate Swaps

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

Other Investments

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net and were not material for 2020 and 2019.

For the years ended December 31, 2020 and 2019

27. 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.

(in millions)	Level 1 (1)	Level 2 (1)	Level 3 (1)	Total
As at December 31, 2020				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	**$ –**	**$ 38**	**$ –**	**$ 38**
Energy contracts not subject to regulatory deferral (2)	**–**	**6**	**–**	**6**
Foreign exchange contracts and total return swaps (2)	**16**	**–**	**–**	**16**
Other investments (4)	**126**	**–**	**–**	**126**
	$ 142	**$ 44**	**$ –**	**$ 186**
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	**$ –**	**$ (94)**	**$ –**	**$ (94)**
Energy contracts not subject to regulatory deferral (5)	**–**	**(12)**	**–**	**(12)**
	$ –	**$ (106)**	**$ –**	**$ (106)**
As at December 31, 2019				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	$ –	$ 22	$ –	$ 22
Energy contracts not subject to regulatory deferral (2)	–	8	–	8
Foreign exchange contracts, interest rate and total return swaps (2)	14	4	–	18
Other investments (4)	121	–	–	121
	$ 135	$ 34	$ –	$ 169
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	$ (1)	$ (138)	$ –	$ (139)
Energy contracts not subject to regulatory deferral (5)	–	(12)	–	(12)
	$ (1)	$ (150)	$ –	$ (151)

(1) Under the hierarchy, fair value is determined using: (i) Level 1 – unadjusted quoted prices in active markets; (ii) Level 2 – other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 – unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.

(2) Included in accounts receivable and other current assets or other assets

(3) Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(4) Included in other assets

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

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

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

Volume of Derivative Activity

As at December 31, 2020, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

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

(1) GWh means gigawatt hours and PJ means petajoules

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts. As a result of the impact of the COVID-19 pandemic, certain of the Corporation's utilities have temporarily suspended non-payment disconnects, delayed customer rate increases and deferred the recovery of costs (Note 2). The Corporation has seen an increase in accounts receivable and, accordingly, its allowance for credit losses during 2020 (Note 6).

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

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

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

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $88 million as at December 31, 2020 (2019 – $161 million).

Hedge of Foreign Net Investments

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

As at December 31, 2020, US$2.3 billion (2019 – US$2.2 billion) of corporately issued US dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.2 billion (2019 – US$9.7 billion) unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's remaining financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2020, the carrying value of long-term debt, including current portion, was $24.5 billion (2019 – $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 – $25.3 billion).

28. COMMITMENTS AND CONTINGENCIES

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

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

(1) FortisBC Electric is a party to an agreement to purchase capacity from the Waneta Expansion for 40 years, beginning April 2015.

(2) *FortisBC Energy ($1,482 million):* includes contracts for the purchase of gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2020.

UNS Energy ($747 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates through 2040.

(3) *Maritime Electric ($910 million):* includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in December 2026.

FortisOntario ($599 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually through December 2030.

FortisBC Electric ($295 million): an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(4) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. Amounts are the estimated future payments.

(5) ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licences associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

(6) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, will be collected from customers in future rates.

(7) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(8) Includes a $24 million payment to be made in 2021 under the Oso Grande Wind Project build-transfer agreement by UNS Energy, as well as AROs and joint-use asset and shared service agreements.

Other Commitments

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

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

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

As at December 31, 2020, FortisBC Holdings Inc. ("FHI") had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right-of-way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2020**	2019[(1)]	2018
Revenue	**8,935**	8,783	8,390
Energy supply costs and operating expenses	**4,999**	4,972	4,782
Depreciation and amortization	**1,428**	1,350	1,243
Gain on disposition	**–**	577	–
Other income, net	**154**	138	60
Finance charges	**1,042**	1,035	974
Income tax expense	**231**	289	165
Earnings from continuing operations	**1,389**	1,852	1,286
Earnings from discontinued operations, net of tax	**–**	–	–
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**1,389**	1,852	1,286
Net earnings attributable to non-controlling interests	**115**	130	120
Net earnings attributable to preference equity shareholders	**65**	67	66
Net earnings attributable to common equity shareholders	**1,209**	1,655	1,100
Balance Sheets *(in $ millions)*			
Current assets	**2,612**	2,574	3,261
Property, plant and equipment, non-utility capital assets[(2)] and intangible assets	**37,289**	35,248	33,957
Goodwill	**11,792**	12,004	12,530
Other long-term assets	**3,788**	3,578	3,303
Total assets	**55,481**	53,404	53,051
Current liabilities	**4,148**	4,176	4,252
Long-term debt (excluding current portion)	**23,113**	21,501	23,159
Other long-term liabilities	**7,936**	7,614	7,184
Total liabilities	**35,197**	33,291	34,595
Total equity	**20,284**	20,113	18,456
Cash Flows *(in $ millions)*			
Operating activities	**2,701**	2,663	2,604
Investing activities	**(4,132)**	(2,768)	(3,252)
Financing activities, excluding dividends	**2,243**	788	1,254
Dividends	**(916)**	(634)	(610)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**7.12**	10.40	7.78
Capitalization Ratios *(%)* (year end)			
Total debt and finance leases (net of cash)	**56.8**	55.1	59.7
Preference shares	**3.7**	4.0	3.9
Common shareholders' equity	**39.5**	40.9	36.4
Interest Coverage *(x)*			
Debt	**2.4**	2.9	2.3
All fixed charges	**2.4**	2.9	2.3
Total capital expenditures *(in $ millions)*	**4,177**	3,818	3,218
Common share data			
Book value per share (year end) *($)*	**36.58**	36.49	34.80
Average common shares outstanding *(in millions)*	**464.8**	436.8	424.7
Basic earnings per common share *($)*	**2.60**	3.79	2.59
Dividends declared per common share *($)*	**1.965**	1.855	1.75
Dividends paid per common share *($)*	**1.9375**	1.8275	1.725
Dividend payout ratio *(%)*	**74.5**	48.2	66.6
Price earnings ratio *(x)*	**20.0**	14.2	17.6
Share trading summary (TSX)			
High price *($)*	**59.28**	56.94	47.36
Low price *($)*	**41.52**	44.00	39.38
Closing price *($)*	**52.00**	53.88	45.51
Volume *(in thousands)*	**441,457**	297,490	269,284

(1) Results were impacted by non-recurring items, largely associated with the disposition of the Waneta Expansion in 2019, the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014 and the acquisition of Central Hudson in 2013.

(2) Non-utility capital assets were sold as part of the sale of commercial real estate and hotel assets in 2015.

Historical Financial Summary

2017	2016 (1)	2015 (1)	2014 (1)	2013 (1)	2012	2011
8,301	6,838	6,757	5,401	4,047	3,654	3,738
4,611	4,372	4,465	3,690	2,654	2,390	2,547
1,179	983	873	688	541	470	416
–	–	–	–	–	–	–
116	53	197	(25)	(31)	4	38
914	678	553	547	389	366	363
588	145	223	66	32	61	84
1,125	713	840	385	400	371	366
–	–	–	5	–	–	–
–	–	–	–	20	–	–
1,125	713	840	390	420	371	366
97	53	35	11	10	9	9
65	75	77	62	57	47	46
963	585	728	317	353	315	311
2,207	2,166	1,857	1,787	1,296	1,093	1,132
30,749	30,348	20,136	18,304	12,612	10,574	9,937
11,644	12,364	4,173	3,732	2,075	1,568	1,565
3,222	3,026	2,638	2,410	1,925	1,715	1,580
47,822	47,904	28,804	26,233	17,908	14,950	14,214
3,504	3,944	2,638	2,676	2,084	1,350	1,305
20,691	20,817	10,784	9,911	6,424	5,741	5,685
6,878	6,693	5,029	4,534	3,024	2,449	2,281
31,073	31,454	18,451	17,121	11,532	9,540	9,271
16,749	16,450	10,353	9,112	6,376	5,410	4,943
2,756	1,884	1,673	982	899	992	915
(3,025)	(6,891)	(1,368)	(4,199)	(2,164)	(1,096)	(1,115)
932	5,491	(14)	3,627	1,434	396	386
(593)	(441)	(332)	(266)	(248)	(225)	(206)
7.31	5.56	9.75	5.45	8.06	8.06	8.79
59.2	60.6	54.8	56.4	56.2	55.3	57.1
4.4	4.4	8.3	9.1	9.0	9.7	8.3
36.4	35.0	36.9	34.5	34.8	35.0	34.6
2.7	2.1	2.7	1.6	1.9	2.0	2.0
2.7	2.1	2.7	1.6	1.9	2.0	2.0
3,024	2,061	2,243	1,725	1,175	1,146	1,171
31.77	32.31	28.62	24.89	22.38	20.84	20.25
415.5	308.9	278.6	225.6	202.5	190.0	181.6
2.32	1.89	2.61	1.41	1.74	1.66	1.71
1.65	1.55	1.43	1.30	1.25	1.21	1.17
1.625	1.525	1.40	1.28	1.24	1.20	1.16
70.0	80.7	53.6	90.8	71.3	72.3	67.8
19.9	21.9	14.3	27.6	17.5	20.6	19.5
48.73	44.87	42.23	40.83	35.14	34.98	35.45
40.59	35.53	34.16	29.78	29.51	31.70	28.24
46.11	41.46	37.41	38.96	30.45	34.22	33.37
205,261	293,991	172,038	174,566	120,470	115,962	126,341

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 17, 2021	August 19, 2021
November 18, 2021	February 15, 2022

Dividend Payment Dates

June 1, 2021	September 1, 2021
December 1, 2021	March 1, 2022

Earnings Release Dates

May 5, 2021	July 29, 2021
October 29, 2021	February 11, 2022

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Montreal and Toronto offices in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and Louisville, KY offices in the United States. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

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

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

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

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

Annual Meeting

Thursday, May 6, 2021 – 10:30 a.m. NDT
To be held virtually

Dividend Reinvestment Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP") as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (minimum of $100, maximum of $30,000 annually) automatically deposited in the plan to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

Share Listings

The Common Shares; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

T: 709.737.2900
F: 709.737.5307
E: investorrelations@fortisinc.com

Fortis Inc. Executive

David G. Hutchens
President and Chief Executive Officer

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President, Sustainability and Chief Human Resource Officer

James P. Laurito
Executive Vice President, Business Development and Chief Technology Officer

James R. Reid
Executive Vice President, Chief Legal Officer and Corporate Secretary

Gary J. Smith
Executive Vice President, Eastern Canadian and Caribbean Operations

Stephanie A. Amaimo
Vice President, Investor Relations

Karen J. Gosse
Vice President, Treasury and Planning

Ronald J. Hinsley
Vice President, Chief Information Officer

Karen M. McCarthy
Vice President, Communications and Corporate Affairs

Regan P. O'Dea
Vice President, General Counsel

James D. Roberts
Vice President, Controller

Photography:
David Howells, St. John's, NL
David Sanders, Tucson, AZ

Design and Production:
m5 Marketing Communications, St. John's, NL www.m5.ca
Moveable Inc., Toronto, ON www.moveable.com

Printer:
The Lowe-Martin Group, Ottawa, ON

Board of Directors

Douglas J. Haughey ✻ ✷ ★
Chair of the Board, Fortis Inc.
Calgary, Alberta

Tracey C. Ball ✻ ★
Corporate Director
Victoria, British Columbia

Pierre J. Blouin ✷ ★
Corporate Director
Montreal, Quebec

Paul J. Bonavia ✷ ★
Corporate Director
Dallas, Texas

Lawrence T. Borgard ✻ ✷
Corporate Director
Naples, Florida

Maura J. Clark ✻ ★
Corporate Director
New York, New York

Margarita K. Dilley ✻ ✷
Corporate Director
Washington, D.C.

Julie A. Dobson ✷ ★
Corporate Director
Potomac, Maryland

David G. Hutchens
President and CEO, Fortis Inc.
Tucson, Arizona

Jo Mark Zurel ✻ ✷
Corporate Director
St. John's, Newfoundland and Labrador

✻ Audit Committee ✷ Human Resources Committee
★ Governance and Sustainability Committee

For Board of Directors' biographies, please visit **www.fortisinc.com.**

FORTIS INC.

Fortis Place | Suite 1100, 5 Springdale Street | PO Box 8837 | St. John's, NL, Canada A1B 3T2
T: 709.737.2800 | F: 709.737.5307 | **www.fortisinc.com** | TSX/NYSE: FTS
info@fortisinc.com | @Fortis_NA | Fortis Inc.

S&P Global
Market Intelligence

Fortis Inc. | Income Statement

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

Source: SNL Financial
Periods: Custom
Magnitude: Thousands (K)
Native Currency: CAD
Current Currency: USD

SNL FINANCIAL	2020 FY	2019 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2020	12/31/2019
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.784806	0.770989
Average Exchange Rate	0.746347	0.753595
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD
Operating Revenue ($000)		
Electric Utility Revenue	3,236,909	3,260,053
Gas Distribution Revenue	1,033,691	1,003,035
Electric Revenue	3,236,909	3,260,053
Oil & Natural Gas Revenue	1,033,691	1,003,035
Other Operating Revenue	2,398,014	2,355,739
Energy Operating Revenue	6,668,614	6,618,827
Operating Expenses ($000)		
Electric Fuel Expense	NA	NA
Cost of Purchased Power	NA	NA
Total Electrical Generation Cost	NA	NA
Gas for Distribution	349,291	330,075
Operations and Maintenance Expense	1,818,849	1,847,815
Other Operating Expenses	1,562,851	1,568,985
Operating DD&A	1,065,784	1,017,354
Taxes, Other than Income Tax	0	0

SNL FINANCIAL	2020 FY	2019 FY
Operating Expense	4,796,775	4,764,229
Operating Margin ($000)		
Income Taxes, Operating	0	0
Recurring Operating Income	1,871,839	1,854,598
Reported Net Operating Income	1,871,839	2,289,422
Other Revenue ($000)		
Partnership Income	NA	NA
Allowance for Equity Funds - Construction	58,215	55,766
Other Noninterest Income	56,722	39,941
Recurring Revenue	6,783,551	6,714,533
Other Nonrecurring Revenue	0	8,290
Gain on Sale of Assets	0	434,824
Nonrecurring Revenue	0	443,114
Total Revenue	6,783,551	7,157,647
Other Expenses ($000)		
Interest Expense: LT Debt	NA	NA
Other Interest Expense	NA	NA
Interest Paid and Accrued	808,294	810,115
Amortization of Deferred Financing Costs	NA	NA
Interest Capitalized	NA	NA
Allowance for Borrowed Funds - Construction	30,600	30,144
Interest Expense	777,694	779,971
Other Expense	0	0
Asset Writedowns	0	0
Other Nonrecurring Expense	0	0
Nonrecurring Expense	0	0
Total Recurring Expense	5,574,469	5,544,200

SNL FINANCIAL	2020 FY	2019 FY
Total Expenses	5,574,469	5,544,200
Net Income ($000)		
Net Income before Taxes	1,209,083	1,613,447
Current Income Taxes	3,732	31,651
Deferred Income Taxes	168,675	186,138
Deferred Tax Credits	0	0
Other Income Taxes	NA	NA
Provision for Taxes	172,406	217,789
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	1,036,677	1,395,658
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	1,036,677	1,395,658
Net Income Attributable to Noncontrolling Int	85,830	97,967
Net Income Attributable to Parent	950,847	1,297,691
Preferred Dividends	48,513	50,491
Other Preferred Dividends after Net Income	0	0
Other Changes to Net Income	0	0
Net Income Avail to Common	902,334	1,247,200
Net Income for Basic EPS	902,334	1,247,200
Net Income for Diluted EPS	902,334	1,247,200

SNL FINANCIAL	2020 FY	2019 FY
Per Share Information ($)		
Basic EPS before Extra	1.94	2.86
Diluted EPS before Extra	1.94	2.85
Basic EPS after Extra	1.94	2.86
Diluted EPS after Extraordinary	1.94	2.85
Avg Basic Shares Out	464,800,000	436,800,000
Avg Diluted Shares (actual)	465,400,000	437,500,000
Common Dividends Declared per Share	1.4666	1.3979

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.

Fortis Inc. | Balance Sheet

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

Source: SNL Financial
Periods: Custom
Magnitude: Thousands (K)
Native Currency: CAD
Current Currency: USD

SNL FINANCIAL	2020 FY	2019 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2020	12/31/2019
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.784806	0.770989
Average Exchange Rate	0.746347	0.753595
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD
Current Assets ($000)		
Cash and Cash Equivalents	195,417	285,266
Gross Trade Accounts Receivable	NA	NA
Trade Accounts Receivable Allowance	NA	NA
Net Customer and Trade Accounts Receivable	416,732	361,594
Other Accounts Receivable	56,506	26,985
Accounts Receivable	473,238	388,579
Unbilled Revenue	448,124	463,365
Current Inventories	331,188	303,770
Prepaid Expense	80,050	67,847
Current Investments	0	0
Short-term Energy Risk-mgmt Assets	NA	NA
Deferred Taxes, Current	0	0
Other Current Assets	521,896	475,700
Current Assets	2,049,914	1,984,526
Property, Plant and Equipment ($000)		
Electric PP&E in Service, Gross	26,879,611	25,429,537

SNL FINANCIAL	2020 FY	2019 FY
Gas PP&E in Service, Gross	6,204,677	5,816,343
Other PP&E in Service, Gross	3,534,767	3,361,513
PP&E in Service, Gross	36,619,055	34,607,393
Total Accumulated Depreciation	9,946,633	9,427,656
Net PP&E in Service	26,672,422	25,179,737
Construction Work in Progress	1,579,030	1,024,645
Net Nuclear Fuel	0	0
Other Net PP&E	127,139	124,900
Net PP&E	28,378,590	26,329,282
Other Assets ($000)		
Securities - Noncurrent	0	0
Nuclear Decommissioning Trust	0	0
Other Investments	51,797	33,153
Investment in Partnerships	62,784	54,740
Noncurrent Investments	114,582	87,893
Goodwill	9,254,434	9,254,955
Intangible Assets other than Goodwill	1,013,185	971,446
Total Intangible Assets	10,267,619	10,226,401
Long-term Energy Risk-mgmt Assets	NA	NA
Deferred Taxes, Noncurrent	0	0
Regulatory Assets	2,351,279	2,191,151
Total Other Assets	379,846	354,655
Total Assets	43,541,830	41,173,908
Tangible Assets	33,274,211	30,947,507
Current Liabilities ($000)		
Short-term Debt	103,594	394,746
Current Portion of Long-term Debt	991,210	556,654
Short-term and Current Long-term Debt	1,094,805	951,401

SNL FINANCIAL	2020 FY	2019 FY
Current Portion of Preferred Equity	0	0
Accrued Interest Payable	168,733	163,450
Income Taxes Payable	0	0
Customer Security Deposits	167,949	174,244
Other Accounts Payable and Accrued Expense	1,254,905	1,272,903
Accounts Payable and Accrued Expense	1,591,587	1,610,596
Short-term Energy Risk-mgmt Liabilities	43,949	63,992
Other Current Liabilities	525,035	593,662
Current Liabilities	3,255,376	3,219,651
Other Liabilities ($000)		
Postretirement Benefits	710,250	641,463
Deferred Income Tax Liability	2,624,392	2,289,067
Deferred Tax Credit	NA	NA
Deferred Tax Liability	NA	NA
Non-current Long-term Debt	18,424,894	16,924,755
Long-term Energy Risk-mgmt Liabilities	39,240	52,427
Regulatory Liabilities	2,089,154	2,147,976
Total Other Liabilities	479,517	391,663
Total Liabilities	27,622,822	25,667,002
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
Equity ($000)		

SNL FINANCIAL	2020 FY	2019 FY
Total Preferred Equity	1,273,740	1,251,316
Common Equity	13,399,780	13,035,886
Equity Attributable to Parent Company	14,673,521	14,287,201
Noncontrolling Interests	1,245,487	1,219,705
Total Equity	15,919,008	15,506,906
Tangible Common Equity	3,132,161	2,809,485
Tangible Equity	5,651,389	5,280,505
Capitalization ($000)		
Equity & Mezzanine Preferred	15,919,008	15,506,906
Total Debt	19,519,699	17,876,156
Total Capitalization, at Book Value	35,438,707	33,383,062
Share Information		
Shares Issued	466,800,000	463,300,000
Treasury Shares	0	0
Common Shares Outstanding (actual)	466,800,000	463,300,000

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 Global
Market Intelligence

Fortis Inc. | Cash Flow Statement

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

Source: SNL Financial
Periods: Custom
Magnitude: Thousands (K)
Native Currency: CAD
Current Currency: USD

SNL FINANCIAL	2020 FY	2019 FY
	Current/Restated	Current/Restated
Fiscal Period Ended	12/31/2020	12/31/2019
Period Restated?	No	No
Restatement Date	NA	NA
Spot Exchange Rate	0.784806	0.770989
Average Exchange Rate	0.746347	0.753595
Accounting Principle	U.S. GAAP	U.S. GAAP
Financials Reported Currency Code	CAD	CAD

Operating Activity ($000)

Net Income	1,036,677	1,395,658
Cash Flow: Depreciation and Amortization	1,065,784	1,017,354
Cash Flow: Amortization of Nuclear Fuel	0	0
Cash Flow: Deferred Taxes & Investment Tax Credits	168,675	186,138
Cash Flow: Operating Changes in AFUDC	(58,215)	(55,766)
Cash Flow: Change in Working Capital	(323,915)	(126,604)
Cash Flow: Other Operating Changes in Cash	126,879	(409,956)
Cash Flow from Operating Activities	2,015,884	2,006,824

Adjusted Cash Flow from Operations ($000)

Net Income	1,036,677	1,395,658
Cash Flow: Depreciation and Amortization	1,065,784	1,017,354
Cash Flow: Deferred Taxes & Investment Tax Credits	168,675	186,138
Cash Flow: Other Operating Changes in Cash	126,879	(409,956)
Cash Flow: Amortization of Nuclear Fuel	0	0
Adjusted Cash Flow from Operations	2,398,014	2,189,194

SNL FINANCIAL	2020 FY	2019 FY
Investing Activity ($000)		
Cash Flow: Capital Expenditures	(2,878,662)	(2,636,830)
Cash Flow from Asset Purchases	(135,835)	(166,545)
Cash Flow from Asset Sales	0	749,827
Cash Flow from Asset Sales & Purchases	(135,835)	583,283
Net Investment in Nuclear Decommissioning Trust	0	0
Cash Flow: Investing Changes in AFUDC	NA	NA
Cash Flow: Other Investing Changes in Cash	(69,410)	(32,405)
Cash Flow from Investing Activities	(3,083,907)	(2,085,952)
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	(308,241)	355,697
Net Proceeds from Issuance of Long-term Debt	6,805,196	5,146,302
Cash Flow: Long-term Debt Repayments	(4,888,575)	(6,003,140)
Net Change in Long-term Debt	1,916,620	(856,838)
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	43,288	1,086,684
Cash Flow: Common Share Repurchases	0	0
Cash Flow: Net Change in Common Issues	43,288	1,086,684
Cash Flow: Common Dividends Paid	(586,629)	(372,276)
Preferred Dividends Paid	(48,513)	(50,491)
Dividends Paid	(635,142)	(422,767)
Cash Flow: Other Financing Changes in Cash	(26,122)	(46,723)
Cash Flow from Financing Activities	990,403	116,054

SNL FINANCIAL	2020 FY	2019 FY
Other Cash Flow ($000)		
Other Cash Flow	(12,688)	(19,593)
Net Increase in Cash and Cash Equivalents	(90,308)	17,333
Mark-to-Market Adjustment	NA	NA
Interest Paid	766,499	758,870
Income Taxes Paid	(19,405)	(27,883)
Dividends Paid to Parent Company	0	0
Projected Capital Expenditures ($000)		
Planned Capital Expenditures for This Fiscal Year	2,992,466	3,346,093
Planned Capital Expenditures for Next Fiscal Year	3,016,010	2,895,065
Planned Capital Expenditures Second Fiscal Year	3,067,022	2,938,240

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.

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

ANNUAL FINANCIAL REPORT

for the period ended

DECEMBER 31, 2020

YEAR ENDED DECEMBER 31, 2020

TABLE OF CONTENTS

FINANCIAL STATEMENTS

	PAGE
CH Energy Group, Inc.	
Consolidated Statement of Income – Year Ended December 31, 2020, 2019 and 2018	4
Consolidated Statement of Comprehensive Income – Year Ended December 31, 2020, 2019 and 2018	4
Consolidated Statement of Cash Flows – Year Ended December 31, 2020, 2019 and 2018	5
Consolidated Balance Sheet – December 31, 2020 and 2019	6
Consolidated Statement of Equity – Year Ended December 31, 2020, 2019 and 2018	8
Central Hudson Gas & Electric Corporation	
Statement of Income – Year Ended December 31, 2020, 2019 and 2018	9
Statement of Comprehensive Income – Year Ended December 31, 2020, 2019 and 2018	9
Statement of Cash Flows – Year Ended December 31, 2020, 2019 and 2018	10
Balance Sheet – December 31, 2020 and 2019	11
Statement of Equity – Year Ended December 31, 2020, 2019 and 2018	13
NOTES TO FINANCIAL STATEMENTS	14
MANAGEMENT'S DISCUSSION AND ANALYSIS	73
ANNUAL FINANCIAL REPORT SUPPLEMENT	108

Deloitte & Touche LLP
City Place I, 33rd Floor
185 Asylum Street
Hartford, CT 06103
USA

Tel: +1 860 725 3000
Fax: +1 860 725 3500
www.deloitte.com

INDEPENDENT AUDITOR'S REPORT

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

We have audited the accompanying consolidated financial statements of CH Energy Group Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits 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 from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements 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, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of CH Energy Group, Inc. and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020 in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Hartford, Connecticut
February 11, 2021

Deloitte.

Deloitte & Touche LLP

City Place I, 33rd Floor
185 Asylum Street
Hartford, CT 06103
USA

Tel: +1 860 725 3000
Fax: +1 860 725 3500

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, 2020 and 2019, the related statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 11, 2021 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 interveners, 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 11, 2021

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

Deloitte.

Deloitte & Touche LLP

City Place I, 33rd Floor
185 Asylum Street
Hartford, CT 06103
USA

Tel: +1 860 725 3000
Fax: +1 860 725 3500

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, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the 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, 2020, of the Company and our report dated February 11, 2021, 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 11, 2021

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, 2020. 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, 2020, the Corporation maintained effective internal control over financial reporting.

The effectiveness of the Corporation's internal control over financial reporting as of December 31, 2020, has been audited by Deloitte and Touche LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/	/s/
Charles A. Freni, Jr. President and Chief Executive Officer	Christopher M. Capone Executive Vice President and Chief Financial Officer

February 11, 2021

CH ENERGY GROUP
CONSOLIDATED STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2020	2019	2018
Operating Revenues			
Electric	$ 552,002	$ 529,460	$ 558,533
Natural gas	159,893	162,203	166,098
Total Operating Revenues	711,895	691,663	724,631
Operating Expenses			
Operation:			
Purchased electricity	136,130	142,085	191,462
Purchased natural gas	37,221	49,430	63,639
Other expenses of operation - regulated activities	306,845	275,898	254,447
Other expenses of operation - non-regulated	208	165	879
Depreciation and amortization	66,863	59,365	54,494
Taxes, other than income tax	67,854	63,623	60,618
Total Operating Expenses	615,121	590,566	625,539
Operating Income	96,774	101,097	99,092
Other Income and Deductions			
Income from unconsolidated affiliates	1,151	1,335	1,044
Interest on regulatory assets and other interest income	2,421	2,604	3,496
Regulatory adjustments for interest costs	(211)	916	1,019
Non-service cost components of pension and other post-employment benefits ("OPEB")	17,744	6,699	1,423
Other - net	2,033	1,101	(1,265)
Total Other Income	23,138	12,655	5,717
Interest Charges			
Interest on long-term debt	32,778	30,861	27,650
Interest on regulatory liabilities and other interest	2,769	3,591	4,532
Total Interest Charges	35,547	34,452	32,182
Income Before Income Taxes	84,365	79,300	72,627
Income Tax Expense	15,262	14,734	15,084
Net Income	$ 69,103	$ 64,566	$ 57,543

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

	Year Ended December 31, 2020	2019	2018
Net Income	$ 69,103	$ 64,566	$ 57,543
Other Comprehensive Income:			
Employee future benefits - net of tax expense	238	(399)	(430)
Comprehensive Income	$ 69,341	$ 64,167	$ 57,113

The Notes to Financial Statements are an integral part hereof.

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

	Year Ended December 31, 2020	2019	2018
Operating Activities:			
Net income	$ 69,103	$ 64,566	$ 57,543
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation	54,558	51,009	47,398
Amortization	12,305	8,356	7,096
Deferred income taxes - net	15,182	15,710	8,020
Uncollectible expense	10,010	7,159	4,799
(Undistributed) distributed equity in earnings of unconsolidated affiliates	(340)	(620)	517
Pension expense	2,340	6,993	13,399
OPEB credit	(6,355)	(7,417)	(5,026)
Regulatory liability - rate moderation	(13,748)	(11,583)	(5,146)
Regulatory asset - revenue decoupling mechanism ("RDM") recorded	22,617	13,064	15,058
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	(14,603)	1,685	(25,788)
Fuel, materials and supplies	2,534	(231)	(2,238)
Special deposits and prepayments	(5,401)	(2,861)	(481)
Income and other taxes	311	(6,355)	7,613
Accounts payable	9,554	(498)	(273)
Accrued interest	581	202	377
Customer advances	389	4,761	(3,779)
Other advances	235	(2,911)	8,777
CARES Act - deferred payroll tax payments	5,206	-	-
Pension plan contribution	(1,130)	(1,050)	(12,194)
OPEB contribution	(1,081)	(1,001)	(1,302)
Regulatory asset - RDM refunded	(12,450)	(16,259)	(3,115)
Regulatory asset - RY 3 - delayed electric and natural gas delivery rate increase	(4,597)	-	-
Regulatory asset - major storm	(19,640)	(3,296)	(28,698)
Regulatory asset - site investigation and remediation ("SIR")	(2,514)	(366)	(1,458)
Regulatory liability - energy efficiency programs including clean energy fund	(17,776)	(3,007)	8,182
Regulatory asset - rate adjustment mechanisms ("RAM")	9,452	4,625	-
Regulatory asset - deferred natural gas and electric costs	4,172	(7,401)	13,643
Other - net	12,115	18,079	25,118
Net cash provided from operating activities	131,029	131,353	128,042
Investing Activities:			
Additions to utility plant	(252,857)	(238,717)	(188,973)
Other - net	(3,975)	934	(217)
Net cash used in investing activities	(256,832)	(237,783)	(189,190)
Financing Activities:			
Repayment of long-term debt	(41,718)	(28,607)	(31,503)
Proceeds from issuance of long-term debt	130,000	100,000	105,000
Net change in short-term borrowings	15,000	-	-
Capital contribution	15,000	29,370	37,000
Dividends paid on Common Stock	-	(16,500)	(22,000)
Other - net	(747)	(559)	(688)
Net cash provided from financing activities	117,535	83,704	87,809
Net Change in Cash, Cash Equivalents and Restricted Cash	(8,268)	(22,726)	26,661
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	21,075	43,801	17,140
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 12,807	$ 21,075	$ 43,801
Supplemental Disclosure of Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 30,967	$ 29,675	$ 26,385
Federal and state income taxes paid, net	$ 52	$ 5,725	$ -
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:			
Operating Cash Flows used in Operating Leases	$ (668)	$ (505)	$ -
Non-Cash Operating Activities:			
Right-of-Use Assets Obtained in Exchange for New Operating Lease Liabilities	$ -	$ 4,599	$ -
Non-Cash Investing Activities:			
Accrued capital expenditures	$ 21,241	$ 23,203	$ 19,342

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP
CONSOLIDATED BALANCE SHEET
(In Thousands)

	December 31, 2020	December 31, 2019
ASSETS		
Utility Plant (Note 3)		
Electric	$ 1,625,696	$ 1,533,547
Natural gas	677,646	615,857
Common	339,329	305,073
Gross Utility Plant	2,642,671	2,454,477
Less: Accumulated depreciation	611,471	580,633
Net	2,031,200	1,873,844
Construction work in progress	126,012	105,057
Net Utility Plant	2,157,212	1,978,901
Non-utility property & plant	524	524
Net Non-Utility Property & Plant	524	524
Current Assets		
Cash and cash equivalents	11,480	19,999
Accounts receivable from customers - net of allowance for uncollectible accounts of $9.4 million and $4.5 million, respectively	77,194	69,171
Accounts receivable - affiliates (Note 18)	1,350	982
Accrued unbilled utility revenues - net of allowance for uncollectible accounts of $1.0 million in 2020 (Note 2)	26,836	24,202
Other receivables	11,527	19,159
Fuel, materials and supplies (Note 1)	23,677	26,211
Regulatory assets (Note 4)	57,079	55,535
Income tax receivable	486	787
Fair value of derivative instruments (Note 16)	18	-
Special deposits and prepayments	32,211	26,810
Total Current Assets	241,858	242,856
Deferred Charges and Other Assets		
Regulatory assets - deferred pension costs (Note 4)	7,551	-
Regulatory assets - other (Note 4)	162,772	123,385
Prefunded OPEB costs (Note 12)	6,497	12,514
Investments in unconsolidated affiliates (Note 6)	9,434	9,169
Other investments (Note 17)	47,912	40,127
Other	10,364	10,363
Total Deferred Charges and Other Assets	244,530	195,558
Total Assets	$ 2,644,124	$ 2,417,839

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, 2020	December 31, 2019
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	424,406	409,406
Retained earnings	431,348	363,445
Accumulated other comprehensive loss	(161)	(399)
Total Equity	855,753	772,612
Long-term debt (Note 11)		
Principal amount	801,510	717,497
Unamortized debt issuance costs	(4,795)	(4,446)
Net long-term debt	796,715	713,051
Total Capitalization	1,652,468	1,485,663
Current Liabilities		
Current maturities of long-term debt (Note 11)	45,987	41,718
Short-term borrowings (Note 9)	15,000	-
Accounts payable	59,081	50,063
Accrued interest	7,614	7,033
Accrued vacation and payroll	11,681	10,754
Customer advances	15,293	14,904
Customer deposits	7,564	7,655
Regulatory liabilities (Note 4)	89,006	94,730
Fair value of derivative instruments (Note 16)	2,153	6,262
Accrued environmental remediation costs (Note 14)	21,020	20,396
Other current liabilities	43,433	40,572
Total Current Liabilities	317,832	294,087
Deferred Credits and Other Liabilities		
Regulatory liabilities - deferred pension costs (Note 4)	-	1,780
Regulatory liabilities - deferred OPEB costs (Note 4)	13,540	26,643
Regulatory liabilities - other (Note 4)	276,600	288,508
Operating reserves	4,970	4,544
Accrued environmental remediation costs (Note 14)	53,883	36,585
Accrued pension costs (Note 12)	25,340	11,228
Tax reserve (Note 5)	-	3,126
Other liabilities	40,566	34,592
Total Deferred Credits and Other Liabilities	414,899	407,006
Accumulated Deferred Income Tax (Note 5)	258,925	231,083
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 2,644,124	$ 2,417,839

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, 2017	15,961,400	$ 160	$ 343,036	$ 279,836	$ -	$ 623,032
Net income				57,543		57,543
Capital contributions			37,000			37,000
Dividends declared on common stock				(22,000)		(22,000)
Employee future benefits, net of tax					(430)	(430)
Balance at December 31, 2018	15,961,400	$ 160	$ 380,036	$ 315,379	$ (430)	$ 695,145
Net income				64,566		64,566
Capital contributions			29,370			29,370
Dividends declared on common stock				(16,500)		(16,500)
Employee future benefits, net of tax					31	31
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

*Accumulated other comprehensive income (loss)

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31,		
	2020	2019	2018
Operating Revenues			
Electric	$ 552,002	$ 529,460	$ 558,533
Natural gas	159,893	162,203	166,098
Total Operating Revenues	711,895	691,663	724,631
Operating Expenses			
Operation:			
Purchased electricity	136,130	142,085	191,462
Purchased natural gas	37,221	49,430	63,639
Other expenses of operation	306,845	275,898	254,447
Depreciation and amortization	66,863	59,365	54,494
Taxes, other than income tax	67,821	63,580	60,586
Total Operating Expenses	614,880	590,358	624,628
Operating Income	97,015	101,305	100,003
Other Income and Deductions			
Interest on regulatory assets and other interest income	2,415	2,572	3,477
Regulatory adjustments for interest costs	(211)	916	1,019
Non-service cost components of pension and OPEB	17,768	6,699	1,304
Other - net	2,046	1,169	(1,239)
Total Other Income	22,018	11,356	4,561
Interest Charges			
Interest on long-term debt	31,978	29,948	26,634
Interest on regulatory liabilities and other interest	2,769	3,583	4,532
Total Interest Charges	34,747	33,531	31,166
Income Before Income Taxes	84,286	79,130	73,398
Income Tax Expense	15,145	14,268	15,217
Net Income	$ 69,141	$ 64,862	$ 58,181

CENTRAL HUDSON
STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31,		
	2020	2019	2018
Net Income	$ 69,141	$ 64,862	$ 58,181
Other Comprehensive Income:			
Employee future benefits - net of tax expense	238	(399)	(430)
Comprehensive Income	$ 69,379	$ 64,463	$ 57,751

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2020	2019	2018
Operating Activities:			
Net income	$ 69,141	$ 64,862	$ 58,181
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation	54,558	51,009	47,398
Amortization	12,305	8,356	7,096
Deferred income taxes - net	15,163	15,346	5,618
Uncollectible expense	10,010	7,159	4,799
Pension expense	2,340	6,993	13,399
OPEB credit	(6,355)	(7,417)	(5,026)
Regulatory liability - rate moderation	(13,748)	(11,583)	(5,146)
Regulatory asset - RDM recorded	22,617	13,064	15,058
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	(14,288)	1,774	(25,788)
Fuel, materials and supplies	2,534	(231)	(2,238)
Special deposits and prepayments	(5,424)	(2,876)	(481)
Income and other taxes	(273)	(8,574)	11,015
Accounts payable	9,019	(599)	(310)
Accrued interest	587	207	380
Customer advances	389	4,761	(3,779)
Other advances	235	(2,911)	8,777
CARES Act - deferred payroll tax payments	5,206	-	-
Pension plan contribution	(1,130)	(1,050)	(12,194)
OPEB contribution	(1,081)	(1,001)	(1,302)
Regulatory asset - RDM refunded	(12,450)	(16,259)	(3,115)
Regulatory asset - RY 3 - delayed electric and natural gas delivery rate increase	(4,597)	-	-
Regulatory asset - major storm	(19,640)	(3,296)	(28,698)
Regulatory asset - SIR	(2,514)	(366)	(1,458)
Regulatory liability - energy efficiency programs including clean energy fund	(17,776)	(3,007)	8,182
Regulatory asset - RAM	9,452	4,625	-
Regulatory asset - deferred natural gas and electric costs	4,172	(7,401)	13,643
Other - net	12,243	16,611	25,034
Net cash provided from operating activities	130,695	128,196	129,045
Investing Activities:			
Additions to utility plant	(252,857)	(238,717)	(188,973)
Other - net	(3,983)	1,820	(145)
Net cash used in investing activities	(256,840)	(236,897)	(189,118)
Financing Activities:			
Repayment of long-term debt	(40,000)	(27,000)	(30,000)
Proceeds from issuance of long-term debt	130,000	100,000	105,000
Net change in short-term borrowings	15,000	-	-
Capital contribution	12,000	11,000	11,500
Other - net	(747)	(559)	(688)
Net cash provided from financing activities	116,253	83,441	85,812
Net Change in Cash, Cash Equivalents and Restricted Cash	(9,892)	(25,260)	25,739
Cash, Cash Equivalents and Restricted Cash - Beginning of Period	15,086	40,346	14,607
Cash, Cash Equivalents and Restricted Cash - End of Period	$ 5,194	$ 15,086	$ 40,346
Supplemental Disclosure of Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 30,162	$ 28,759	$ 25,365
Federal and state income taxes paid, net	$ 501	$ 7,670	$ -
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:			
Operating Cash Flows used in Operating Leases	$ (668)	$ (505)	$ -
Non-Cash Operating Activities:			
Right-of-Use Assets Obtained in Exchange for New Operating Lease Liabilities	$ -	$ 4,599	$ -
Non-Cash Investing Activities:			
Accrued capital expenditures	$ 21,241	$ 23,203	$ 19,342

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON
BALANCE SHEET
(In Thousands)

	December 31, 2020	December 31, 2019
ASSETS		
Utility Plant (Note 3)		
Electric	$ 1,625,696	$ 1,533,547
Natural gas	677,646	615,857
Common	339,329	305,073
Gross Utility Plant	2,642,671	2,454,477
Less: Accumulated depreciation	611,471	580,633
Net	2,031,200	1,873,844
Construction work in progress	126,012	105,057
Net Utility Plant	2,157,212	1,978,901
Non-Utility Property and Plant	524	524
Net Non-Utility Property and Plant	524	524
Current Assets		
Cash and cash equivalents	3,867	14,010
Accounts receivable from customers - net of allowance for uncollectible accounts of $9.4 million and $4.5 million, respectively	77,194	69,171
Accrued unbilled utility revenues - net of allowance for uncollectible accounts of $1.0 million in 2020 (Note 2)	26,836	24,202
Other receivables	11,715	19,295
Fuel, materials and supplies (Note 1)	23,677	26,211
Regulatory assets (Note 4)	57,079	55,535
Fair value of derivative instruments (Note 16)	18	-
Special deposits and prepayments	32,211	26,787
Total Current Assets	232,597	235,211
Deferred Charges and Other Assets		
Regulatory assets - deferred pension costs (Note 4)	7,551	-
Regulatory assets - other (Note 4)	162,772	123,385
Prefunded OPEB costs (Note 12)	6,497	12,514
Other investments (Note 17)	47,020	39,301
Other	10,364	10,363
Total Deferred Charges and Other Assets	234,204	185,563
Total Assets	$ 2,624,537	$ 2,400,199

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON

BALANCE SHEET (CONT'D)

(In Thousands, except share amounts)

	December 31, 2020	December 31, 2019
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	274,452	262,452
Accumulated other comprehensive loss	(161)	(399)
Retained earnings	498,398	430,457
Capital stock expense	(4,633)	(4,633)
Total Equity	852,367	772,188
Long-term debt (Note 11)		
Principal amount	792,800	706,950
Unamortized debt issuance costs	(4,748)	(4,390)
Net long-term debt	788,052	702,560
Total Capitalization	1,640,419	1,474,748
Current Liabilities		
Current maturities of long-term debt (Note 11)	44,150	40,000
Short-term borrowings (Note 9)	15,000	-
Accounts payable	58,906	50,423
Accrued interest	7,585	6,998
Accrued vacation and payroll	11,681	10,754
Customer advances	15,293	14,904
Customer deposits	7,564	7,655
Regulatory liabilities (Note 4)	89,006	94,730
Fair value of derivative instruments (Note 16)	2,153	6,262
Accrued environmental remediation costs (Note 14)	21,020	20,396
Accrued income and other taxes	-	273
Other current liabilities	41,384	38,006
Total Current Liabilities	313,742	290,401
Deferred Credits and Other Liabilities		
Regulatory liabilities - deferred pension costs (Note 4)	-	1,780
Regulatory liabilities - deferred OPEB costs (Note 4)	13,540	26,643
Regulatory liabilities - other (Note 4)	276,600	288,508
Operating reserves	4,970	4,544
Accrued environmental remediation costs (Note 14)	53,883	36,585
Accrued pension costs (Note 12)	25,107	10,996
Tax reserve (Note 5)	-	2,910
Other liabilities	37,946	32,347
Total Deferred Credits and Other Liabilities	412,046	404,313
Accumulated Deferred Income Tax (Note 5)	258,330	230,737
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 2,624,537	$ 2,400,199

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, 2017	16,862,087	$ 84,311	$ 239,952	$ (4,633)	$ 307,414	$ -	$ 627,044
Net income					58,181		58,181
Capital contributions			11,500				11,500
Employee future benefits, net of tax						(430)	(430)
Balance at December 31, 2018	16,862,087	$ 84,311	$ 251,452	$ (4,633)	$ 365,595	$ (430)	$ 696,295
Net income					64,862		64,862
Capital contributions			11,000				11,000
Employee future benefits, net of tax						31	31
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 contribution			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

*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, 2020 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, 2020 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 evolution of the novel Coronavirus pandemic ("COVID-19"), which could affect the allowance for credit losses, as well as the total impact and potential recovery of incremental costs associated with COVID-19.

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 companies, 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 New York State Public Service Commission ("PSC" or "Commission"), 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 is met. Current accounting practices reflect the regulatory accounting authorized in Central Hudson's most recent Rate Order. 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 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, the 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 Federal Energy Regulatory Commission ("FERC") and are collected via the Open Access Transmission Tariff ("OATT") administered by the New York Independent System Operator ("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 2018 Rate Order. 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 kWh or 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 COVID-19 pandemic on our customers.

Central Hudson records an estimate of unbilled revenue for service rendered to customers subsequent to their billing date and through the end of the month. Unbilled revenues are dependent upon a number of 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 2018 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 reducing costs, reaching specified milestones, or improving customer service. 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 System Deliverability Upgrade 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, 2020	December 31, 2019
Cash and cash equivalents	$ 11,480	$ 19,999
Restricted cash included in other long-term assets	1,327	1,076
Total cash, cash equivalents and restricted cash shown in the statement of cash flows	$ 12,807	$ 21,075

Central Hudson

(In Thousands)

	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 3,867	$ 14,010
Restricted cash included in other long-term assets	1,327	1,076
Total cash, cash equivalents and restricted cash shown in the statement of cash flows	$ 5,194	$ 15,086

Accounts Receivable and Allowance for Uncollectible Accounts

Beginning on January 1, 2020, 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. Interest 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 COVID-19 on interest charges and other revenue.

As of December 31, 2019, receivables were carried at net realizable value based on the allowance for doubtful accounts model. Estimates for uncollectible accounts were based on customer accounts receivable aging data, as well as, consideration of various quantitative and qualitative factors, including special collection issues.

Financial Instruments

Effective January 1, 2020, CH Energy Group and Central Hudson adopted accounting guidance that requires the use of 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. At December 31, 2020 there are no expected credit losses on financial instruments other than those on accounts receivable and unbilled utility revenues.

Fuel, Materials & Supplies

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

	December 31, 2020	December 31, 2019
Natural gas [1]	$ -	$ 4,823
Fuel used in electric generation	373	413
Materials and supplies	23,305	20,975
Total	$ 23,677	$ 26,211

(1) Effective August 1, 2020 Central Hudson has entered into an Asset Management Agreement 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 gas in storage until the end of the contract term. As such, these balances were transferred from natural gas within Fuel, materials and supplies to 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 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. The AFUDC rate was 5.95% in 2020, 6.4% in 2019 and 6.0% in 2018.

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, is 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 cost of removal recovered in excess of 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, was 2.90% in 2020, 2.77% in 2019 and in 2018 was 2.75% of the original average cost of depreciable property. The ratio of the amount of accumulated depreciation to the original cost of depreciable property at December 31, 2020, 2019, and 2018 was 23.3%, 23.9% and 24.5%, 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 expense 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 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 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 that transferred to an affiliate company but continues to accrue benefits in Central Hudson's Pension and OPEB. The related amounts will be charged to and reimbursed by the affiliate company in future periods.

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 is 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 in Other Net in the December 31, 2019 and 2018 CH Energy Group and Central Hudson Statements of Income have been reclassified to disclose the Non-service cost components of pension and OPEB and conform to the 2020 presentation. These reclassifications had no effect on the reported results of operations.

Certain amounts shown in Note 4 – "Regulatory Matters" and Note 5 – "Income Taxes" related to prior year, have been reclassified to conform to the 2020 presentation. These reclassifications had no effect on the reported results of operations.

Recently Adopted Accounting Pronouncements

Financial Instruments

Effective January 1, 2020, CH Energy Group and Central Hudson adopted Accounting Standards Update ("ASU") No. 2016-13 *Measurement of Credit Losses on Financial Instruments* which requires entities to use a current expected credit loss ("CECL") model that is based on expected losses rather than incurred losses. Under the CECL model, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board ("FASB") believes will result in more timely recognition of such losses. Adoption of this ASU requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. The adoption of this ASU resulted in an increase to CH Energy Group and Central Hudson's allowance for credit losses of $1.2 million and was recorded as a cumulative adjustment to retained earnings effective January 1, 2020.

Future Accounting Pronouncements To Be Adopted

Soon to be adopted accounting guidance is summarized below, including explanations for any new guidance issued by FASB (except that which is not currently applicable) and the expected impact on CH Energy Group and its subsidiaries.

Income Taxes

ASU No. 2019-12, *Simplifying the Accounting for Income Taxes*, was issued in December 2019 to simplify the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740 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 simplifies 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. The amendment is effective for annual reporting periods beginning after December 15, 2020, and interim periods within those reporting periods. Early adoption of all changes is permitted in any interim or annual period, with any adjustments reflected as of the beginning of the fiscal year of adoption. Upon adoption, entities should disclose the nature and reason for the change in accounting principle, the transition methods, and a qualitative description of the financial statement line items affected by the change. CH Energy Group and its subsidiaries do not expect the adoption of this standard to have a material impact on their earnings, financial position, cash flows or financial disclosures.

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 2020 three-month postponement of the electric and natural gas delivery rate increase, Gas Merchant Function Charge lost revenue, and revenue requirement effect for incremental Leak Prone Pipe ("LPP") miles replaced above the PSC targets. In addition, Central Hudson records alternative revenues related to positive revenue adjustments 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	2020	2019	2018
Revenues from Contracts with Customers (ASC 606)	$ 547,586	$ 512,787	$ 574,908
Alternative Revenues (Non ASC 606)	(18,268)	(11,755)	(15,506)
Other Revenue Adjustments (Non ASC 606)	22,684	28,428	(869)
Total Operating Revenues Electric	$ 552,002	$ 529,460	$ 558,533
Natural Gas			
Revenues from Contracts with Customers (ASC 606)	$ 155,391	$ 161,385	$ 169,159
Alternative Revenues (Non ASC 606)	9,281	4,664	5,299
Other Revenue Adjustments (Non ASC 606)	(4,779)	(3,846)	(8,360)
Total Operating Revenues Natural Gas	$ 159,893	$ 162,203	$ 166,098

In 2020, the increase in electric revenues from contracts with customers is primarily driven by the increase in customer delivery rates and billed RAM and EAM surcharges. For natural gas, the decrease in 2020 revenue from contracts with customers is due to lower natural gas commodity cost driven by both, lower price and sales volume, partially offset by the increase in delivery rates and billed RAM and EAM surcharges. Revenue from contracts with customers for both electric and natural gas also include higher credits to customer bills for rate moderation in 2020 when compared to 2019, which does not impact total revenues. The offset of these credits is reflected in other revenue.

The decrease in electric alternative revenue programs for 2020 is due to an increase in the deferral of actual billed revenues in excess of the 2018 Rate Order prescribed targets, partially offset by the deferral of the delivery rate increase which was delayed from July 1, 2020 to October 1, 2020. The increase in natural gas alternative revenue programs for 2020 is primarily due to the deferral of actual revenues below the 2018 Rate Order prescribed targets.

For electric and gas, the decrease in other revenues for 2020 compared to 2019 were primarily driven by the discontinuation of finance charges on customers' past due balances to mitigate the impacts of the COVID-19 pandemic on customers.

Allowance for Uncollectible Accounts

Accounts receivable are recorded net of an allowance for uncollectible accounts based on the allowance for credit losses model. Upon adoption of the new accounting standard, the Company recorded the cumulative effect adjustment increasing its allowance for uncollectible accounts receivable by $0.7 million and established an allowance on accrued unbilled utility revenues of $0.5 million.

A summary of all changes in the allowance for uncollectible accounts receivable and accrued unbilled utility revenue balance is as follows:

	Year Ended	
	December 31, 2020	December 31, 2019[1]
Balance at Beginning of Period	$ (4,500)	$ (2,700)
Accounting Standard Adoption – cumulative effect adjustment	(1,200)	N/A
Uncollectible expense	(10,010)	(7,159)
Bad debt write-offs (recoveries) - net	5,310	5,359
Balance at End of Period	$ (10,400)	$ (4,500)

(1) December 31, 2019 reserve is based on the allowance for doubtful accounts model.

During the twelve months ended December 31, 2020, management recorded an additional increase to the allowance for uncollectible accounts of $4.9 million based on a quantitative and qualitative assessment of forecasted economic conditions related to COVID-19. This assessment included a historical analysis of the relationship of write-offs to accounts receivable balances in arrears and taking into consideration certain qualitative factors differentiating this current situation from other significant events in the historical period, including the nature and cause of this economic downturn, as well as legislative actions taken which provide relief and assistance to customers financially impacted by the COVID-19 pandemic.

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, 2020	Utility Plant December 31, 2019
Electric:			
Production	25-85	$ 42,992	$ 42,961
Transmission	30-90	435,855	403,242
Distribution	7-80	1,139,941	1,080,869
Other	40	6,908	6,475
Total		$ 1,625,696	$ 1,533,547
Natural Gas:			
Transmission	19-85	$ 61,476	$ 59,608
Distribution	28-95	615,728	555,807
Other	N/A	442	442
Total		$ 677,646	$ 615,857
Common:			
Land and Structures	50	$ 88,310	$ 86,278
Office and Other Equipment, Radios and Tools	8-35	79,429	72,911
Transportation Equipment	10-12	77,668	73,017
Other	3-10	93,922	72,867
Total		$ 339,329	$ 305,073
Gross Utility Plant		$ 2,642,671	$ 2,454,477

For the years ended December 31, 2020, 2019 and 2018 the borrowed component of funds used during construction and recorded as a reduction of interest expense was $1.5 million, $1.2 million and $1.1 million, respectively, and the equity component reported as other income was $3.0 million for the year ended December 31, 2020, $2.3 million in 2019 and $2.1 million in 2018.

Included in the Net Utility Plant balance of $2.2 billion and $2.0 billion at December 31, 2020 and 2019 is $141.7 million and $115.0 million of intangible utility plant assets, comprised primarily of computer software costs, land, transmission, and water and other rights, and the related accumulated amortization of $64.7 million and $52.4 million, respectively. Amortization expense is estimated to average approximately $8.3 million annually for each of the next five years.

As of December 31, 2020 and 2019, Central Hudson has reclassified from accumulated depreciation $40.4 million and $43.0 million, respectively, of cost of removal recovered through the rate-making process in excess of amounts incurred to date as a regulatory liability.

As of December 31, 2020 and 2019, AROs for Central Hudson were approximately $1.9 million and $0.6 million, respectively. 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, 2020		December 31, 2019	
Regulatory Assets:				
Deferred purchased electric costs (Note 1)	$ 3,470		$ 8,013	
Deferred purchased natural gas costs (Note 1)	4,453		4,082	
Deferred unrealized losses on derivatives - electric and natural gas (Note 16)	2,153		6,262	
RAM - electric	13,866		13,518	
RAM - natural gas	3,418		3,201	
EAMs - electric	3,410		2,118	
SC 8 Street Lighting	1,678		913	(1)
Delayed electric and natural gas delivery rate increase	4,596		-	
RDM and carrying charges - natural gas	3,778		2,518	
Energy efficiency programs and carrying charges	1,260		-	
Revenue requirement of LPP replacement	1,696		-	(1)
Deferred pension costs (Note 12)	7,551		-	
Demand management programs	11,032		10,747	
Deferred and accrued costs - SIR (Note 14)	84,370		62,694	
Deferred storm costs	19,902		11,420	
Deferred vacation pay accrual	10,197		8,384	
Income taxes recoverable through future rates	26,968		22,253	
Tax reform - unprotected impacts (Note 5)	13,464		13,464	
Other	10,140	(2)	9,333	(1)(2)
Total Regulatory Assets	$ 227,402		$ 178,920	
Less: Current Portion of Regulatory Assets	$ 57,079		$ 55,535	
Total Long-term Regulatory Assets	$ 170,323		$ 123,385	
Regulatory Liabilities:				
Rate moderator - electric	$ 15,786		$ 26,583	
Rate moderator - natural gas	6,247		7,959	
RDM and carrying charges - electric	22,073		10,735	
Clean Energy Fund and carrying charges	57,893		68,277	
Tax reform - protected deferred tax liability (Note 5)	183,915		189,447	
Deferred cost of removal (Note 3)	40,384		43,039	
Deferred pension costs (Note 12)	-		1,780	
Income taxes refundable through future rates	9,149		7,896	
Deferred OPEB costs (Note 12)	13,540		26,643	
Low income program	4,722		1,967	(1)
Net plant and depreciation targets	10,193		6,082	
Fast charging infrastructure program and carrying charges	5,124		4,584	
Energy efficiency programs and carrying charges	-		4,999	
Deferred unbilled revenue	5,082		5,082	
Other	5,038	(2)	6,588	(1)(2)
Total Regulatory Liabilities	$ 379,146		$ 411,661	
Less: Current Portion of Regulatory Liabilities	$ 89,006		$ 94,730	
Total Long-term Regulatory Liabilities	$ 290,140		$ 316,931	
Net Regulatory Liabilities	$ (151,744)		$ (232,741)	

(1) Balances reported in the Other regulatory assets and liabilities lines as of December 31, 2019 have been reclassified to conform to the December 31, 2020 presentation.

(2) 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.

The significant regulatory assets and liabilities include:

Rate Adjustment Mechanism: Mechanism prescribed in the 2018 Rate Order to recover from or refund to customers previously deferred balances related to major storms 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.

Earnings Adjustment Mechanism: Mechanism prescribed in the 2018 Rate Order to recover from customers incentives earned related to energy efficiency targets met.

SC8 Street Lighting: This regulatory asset represents the deferral to reassign the collection of revenues amongst certain service classes as prescribed in the July 22, 2019 Order and discussed further below.

Delayed electric and natural gas delivery rate increase: This regulatory asset represents the deferral of the electric and natural gas delivery rate increases as prescribed in the June 11, 2020 Order as further discussed below.

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

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.

Revenue requirement of LPP replacement: This regulatory asset represents the deferral of the revenue requirement impact related to the replacement of LPP as prescribed in the 2018 Rate Order.

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 to be collected in the current rate term are authorized to be collected via its RAM, to the extent sufficient.

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 Rate Order, which will be used for future customer rate moderation, as well as deferred Danskammer Generating Station delivery revenues for future natural gas rate moderation.

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

Low Income Program: This regulatory liability represents deferred balances for amounts collected in excess of credits provided for low income 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 Station 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.

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, 2020	December 31, 2019
Balances with offsetting accrued liability balances recoverable when future costs are actually incurred:		
Deferred pension related to underfunded status	$ 7,551	$ -
Income taxes recoverable through future rates	26,968	22,253
Deferred unrealized losses on derivatives - electric	2,122	5,542
Deferred unrealized losses on derivatives - natural gas	31	720
Accrued SIR costs	74,903	56,981
Deferred ARO	406	475
Deferred vacation pay accrual	10,197	8,384
	$ 122,178	$ 94,355
Balances earning a return via inclusion in rates and/or the application of carrying charges:		
Energy Efficiency Programs and carrying charges	$ 1,260	$ - (2)
OPEB reserve carrying charges	1,828	1,100 (2)
Deferred storm costs	19,902	11,420
Deferred SIR costs, net of recoveries	9,467	5,713
Deferred debt expense on re-acquired debt	1,860	2,377
Tax reform - unprotected deferred tax asset	13,464	13,464
Other	5,340	4,184 (2)
	$ 53,121	$ 38,258
Subject to current recovery:		
Deferred purchased electric costs	$ 3,470	$ 8,013
Deferred purchased natural gas costs	4,453	4,082
Delayed electric and natural gas delivery rate increase	4,596	-
RAM - electric and natural gas	17,285	16,719
EAMs - electric	3,410	2,118 (2)
RDM - electric and natural gas	3,778	2,518
Demand management programs(1)	11,032	10,747
Other	5,068	2,629 (2)
	$ 53,092	$ 46,826

Accumulated carrying charges:				
Carrying charges balancing	$	(1,010)	$	(519)
Other		21		-
	$	(989)	$	(519)
Total Regulatory Assets	$	227,402	$	178,920

(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.

(2) Certain amounts shown for the period ended December 31, 2019 have been reclassified to conform to the December 31, 2020 presentation.

PSC Proceedings

2018 Rate Order and Related Proceedings

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 adopted the terms set forth in the April 18, 2018 Joint Proposal with minor modifications. The 2018 Rate Order was effective July 1, 2018, with Rate Year ("RY")1, RY2 and RY3 defined as the twelve months ending June 30, 2019, June 30, 2020 and June 30, 2021, respectively.

A summary of the key terms of the 2018 Rate Order is as follows:

	2018 Rate Order (dollars in millions)		
Description	RY1	RY2	RY3
Electric delivery rate increases	$19.7	$18.6	$25.1
Natural gas delivery rate increases	$6.7	$6.7	$8.2
Return on Equity	8.80%	8.80%	8.80%
Earnings sharing	Yes(1)	Yes(1)	Yes(1)
Capital structure – common equity	48%	49%	50%
Bill Credits - Electric	$6.0	$9.0	$11.0
Bill Credits - Natural Gas	$3.5	$4.0	$4.0
RDMs – electric and natural gas	Yes	Yes	Yes

(1) Return on equity > 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.

Key provisions of the 2018 Rate Order include:

Revenue increases net of bill credits result in average residential monthly bill impacts of 1.3%, 3.0% and 4.4% for electric customers and 2.1%, 4.4% and 5.5% for natural gas customers in RYs 1, 2, and 3, respectively, of the rate plan. The rates reflect a reduction to the customer charge for residential and electric small commercial classes. Electric RDM has been expanded to include additional service classes. During the three year term, approximately 97% of electric base delivery revenues and 92% of natural gas base delivery revenues are covered by RDMs. A RAM was approved to return or collect certain deferred balances and carrying charges on a more timely basis (subject to calendar year caps).

The revenue requirements reflect authorization for capital expenditures of more than $650 million over the term covered by the 2018 Rate Order, including a significant increase in information technology investments, funding to begin implementing a multi-year plan to construct a Training Center and Primary Control Center, continued investment for LPP Replacement, and funding for Distribution Automation and Network Strategy. The revenue requirement also reflects an increase in funding for Transmission and Distribution Right of Way Maintenance, increased low income discounts, funding to eliminate credit/debit card and walk-in center payment fees charged to customers and an increase in energy efficiency program funding which was moved into base delivery rates.

The 2018 Rate Order introduced five electric and one natural gas EAMs with targets set for minimum, midpoint and maximum performance. Potential maximum earnings adjustments total $2.2 million in 2018, $4.7 million in 2019, $5.1 million in 2020 and $5.4 million in 2021. As of December 31, 2020, 2019 and 2018, the Company has earned $2.6 million, $2.1 million and $0.6 million related to electric EAM targets, respectively.

The 2018 Rate Order changed various performance mechanisms for electric, natural gas and customer service. For electric reliability, the System Average Interruption Frequency Index target was raised to 1.38 for 2018 and lowered to 1.34 for 2019 and 1.30 for 2020, respectively. Gas safety metric targets were restated for calendar year 2018 and other changes were made including revised targets for all gas metrics, a reduction to potential NRAs and additional positive revenue adjustments for surpassing certain gas safety metrics. The 2018 Rate Order also includes more stringent Customer Satisfaction and PSC Complaint targets, and new Call Answer Rate and Residential Termination/Uncollectible metrics with the net result of a reduction in the total potential NRAs.

On July 22, 2019, the Commission issued an Order approving Central Hudson's petition to modify the revenue allocation provisions and certain RDM targets of Central Hudson's service class 8 (public street and highway lighting customers) as approved in the 2018 Rate Order and the authority to defer and recover revenues to address an overestimate of lighting fixtures forecasted in a street lighting category which resulted in a misallocation of the revenue requirement that should have been recovered from all other Central Hudson customer classes. The annual impact is a shift of approximately $0.5 million, $0.7 million and $0.9 million for RY1, RY2 and RY3, respectively, which is de minimis when allocated and collected from the non-lighting customer classes. The Order reassigned the collection of revenues amongst the service classes with no impact on Central Hudson's results of operations.

On June 11, 2020, the Commission issued 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 increase 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 states that no carrying charges will be applied to the delayed recovery of these revenues and that Central Hudson will adjust the RDM Targets to be consistent with the delayed electric and natural gas delivery rate increase implementation.

<u>August 2020 Rate Filing</u>

Central Hudson filed an electric and natural gas rate case (Cases 20-E-0428 and 20-G-0429) on August 27, 2020 with the PSC seeking electric and natural gas delivery revenue increases of $32.8 million and $14.4 million, respectively, to become effective July 1, 2021. The filing includes net regulatory liability balances proposed for rate moderation of $20 million for electric and $8 million for natural gas. The rate filing was made in order to align electric and natural gas delivery rates with the projected costs of providing service to our customers and reflects a return on equity of 9.1% and a 50.0% equity ratio to maintain financial integrity. Additionally, due to the severe economic impact of COVID-19 within its service territory, Central Hudson included specific actions within the filing to reduce the customer bill impact, which included delaying a meaningful portion of the capital plan ($48.5 million during the rate year ending June 30, 2022) and a COVID-19 Adjustment Customer Bill Moderation credit that reduces Central Hudson's revenue requirements by $1.8 million for electric and $0.5 million for natural gas.

The primary drivers for the increase in projected costs include: 1) capital investments to modernize Central Hudson's electric, gas infrastructure and information technology ("IT") systems resulting in increases in depreciation expense, return on rate base, and property taxes; 2) increasing expenses associated with vegetation management or trimming; 3) increasing employee levels and labor costs;

and 4) initiation of a new Heat Pump program. Modernization of electric transmission and distribution infrastructure addresses the underlying age and condition of the assets and the need to enable the Distributed System Platform in order to better monitor and control the distribution system while facilitating increasing levels of Distributed Energy Resources penetration. This is directly tied to the goals of Climate Leadership and Community Protection Act. Central Hudson's filing also proposes the continued replacement of gas LPP, replacing 15 miles per year resulting in an elimination of LPP from the Company's gas system in approximately eight years. Central Hudson also proposes to invest in IT systems to transform and modernize customer interactions, complete the replacement of its 40-year old Enterprise Resource Planning mainframe solution and sustain the security and maintenance of our IT systems. Central Hudson is also proposing additional funding to maintain a four-year cycle for distribution line clearance and a five-year cycle for its transmission right-of way trimming maintenance while implementing a targeted tree removal program aimed at reducing the impact of the increasing number of severe weather events brought about by climate change and the proliferation of invasive insect infestations and tree diseases. Central Hudson is also seeking recovery of costs associated with the New York State Clean Heat program, which seeks to replace high carbon intensive heating sources with heat pumps and related measures.

The filing also proposes to:

1) modify and expand the current EAMs that were approved in the 2018 Rate Order;
2) introduce new Positive Revenue Adjustments while eliminating or modifying the structure of certain NRAs;
3) expansion of Central Hudson's RDMs to include additional service classes;
4) institute new deferral mechanisms, including authority to defer incremental COVID-19 related costs and lost revenues; and
5) expand the eligibility criteria for the Low Income Bill Discount Program to include customers who receive other forms of public assistance.

COVID-19 Proceeding

On June 11, 2020, the Commission established a new proceeding under Case 20-M-0266 to identify and address the effects of the COVID-19 pandemic on utility service in New York State. 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 Commission's clean energy programs should be maintained or accelerated. Public comments on the collection and termination of service, commission principles in serving the public interest and rate and financial aspects, as provided in an Appendix to the Order, were filed by parties on July 13, 2020 and reply comments were filed August 28, 2020. As requested by Staff, utilities are providing on a monthly basis, financial information to enable an assessment of the COVID-19 impacts on utility earnings and cash flow. Central Hudson is providing monthly reports to Staff with regards to COVID-19 lost finance charge revenues and incremental costs, including the change in past due customer balances, the uncollectible reserve and cost reductions.

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. On August 19, 2020, the Office of Investigations and Enforcement of the DPS issued a Notice of Apparent Violations Related to Tropical Storm Isaias (the "Notice") to the Company. The Notice identified two potential violations based on the Staff's initial investigation into Central Hudson's storm response to Tropical Storm Isaias. On November 19, 2020, DPS Staff 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 ("ERPs"). On the same day, the Commission issued an Order to Commence Proceeding and Show Cause ("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 result in up to $16 million of penalties. The Show Cause Order directed the utilities to respond to the allegations of noncompliance within 30 days and to show cause why civil penalties or appropriate injunctive relief should not be imposed to remedy such noncompliance. 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, believes no penalty should be issued because the facts demonstrate that Central Hudson fully complied with its PSC approved ERP, which serves as the standard against which Central Hudson should be evaluated. As such, no accrual has been made related to this Proceeding and Show Cause Order or the Notice. Management cannot predict the outcome of this matter or the impact it may have on Central Hudson's earnings, financial position or cash flows.

Central Hudson Reverse Sales Tax Refund

On March 16, 2020, Central Hudson filed a petition for the disposition of a sales tax refund, pursuant to PSL Section 113(2) under Case 20-M-0134. The tax refund is the result of a reverse sales tax audit that Central Hudson initiated with the New York State Department of Taxation & Finance for the claim period of June 1, 2017 through December 31, 2018. The Commission solicited comments on the filing via notice published in the April 22, 2020 edition of the New York State Register. Central Hudson asked the Commission to take notice of a tax refund received from the New York State Department of Taxation and Finance, in the amount of approximately $3.4 million on October 16, 2019 and waive the rule requiring the Company to give the Commission notice of the refund within 60 days. Central Hudson proposed that the refund received be allocated (1) for the benefit of ratepayers; and (2) to reimburse the costs incurred by Central Hudson in securing the refund. The Company proposed to retain approximately $0.6 million, or 24% of the refund, net of costs to achieve. Most of the refund has been credited to plant as the majority of the refund related to sales taxes that were capitalized as part of plant costs. The petition requested the PSC approve Central Hudson retaining the portion of the net refund related to amounts that were previously recorded to sales tax expense. Staff's testimony in the August 2020 filing requested that this proceeding be incorporated into the August 2020 Rate Case filing rather than ruled upon separately. Although the outcome is unknown, any potential adjustments that may result from a PSC ruling differing from how the refund has been recorded to date, is not expected to be material to Central Hudson's financial statements.

Central Hudson 2018 Financing Order

On September 13, 2018, the Commission approved the Company's request under Section 69 of the Public Service Law to enter into multi-year committed credit agreements in an aggregate amount not to exceed $200 million and maturities not to exceed five years, to issue and sell long-term debt in an aggregate amount not to exceed $425 million through December 2021, and to enter into derivative instruments to hedge interest rate risk for its variable rate debt obligations.

FERC 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 System Deliverability Upgrades ("SDU") 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.

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 activity related to the uncertain tax position (In Thousands):

	CH Energy Group Year Ended December 31,		Central Hudson Year Ended December 31,	
	2020	2019	2020	2019
Tax reserve balance at the beginning of the period	$ 3,126	$ 7,675	$ 2,910	$ 7,675
Change in natural gas transmission and distribution repair deduction	985	504	985	504
Change in tax benefit offset [1]	(4,111)	(5,053)	(3,895)	(5,269)
Tax reserve balance at the end of the period	$ -	$ 3,126	$ -	$ 2,910

(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	2017 – 2019
New York State	2017 – 2019

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 normalization rules. The Company also recorded a regulatory asset due to the revaluation of non-plant related deferred taxes, which is not subject to the normalization rules. The balance will be addressed in the Company's 2020 Rate Filing.

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, 2020	December 31, 2019
Protected Regulatory Liability at the beginning of the period	$ 189,447	$ 194,513
Amortization of Protected Tax Liability	(5,532)	(5,066)
Protected Regulatory Liability at the end of the period	$ 183,915	$ 189,447

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

	December 31, 2020	December 31, 2019
Unprotected Regulatory Asset at the beginning of the period	$ 13,464	$ 13,688
Change in Unprotected Tax Asset	-	(224)
Unprotected Regulatory Asset at the end of the period	$ 13,464	$ 13,464

Coronavirus Aid, Relief, and Economic Security ("CARES") Act

The CARES Act was signed into law on March 27, 2020. As permitted under the CARES Act, Central Hudson is currently deferring payment of the employer share of the Social Security tax on its payroll during 2020. The deferred payroll tax can be paid over the next two years—with half of the required amount paid by December 31, 2021 and the other half by December 31, 2022. No other provisions of the CARES Act currently apply to Central Hudson. There is no impact on earnings or on the effective tax rate resulting from the delayed payment of employer payroll tax under the CARES Act as the expense, liability and associated deferred taxes have been reflected in the current period. As of December 31, 2020, the liability for the deferred payment of the employer's portion of Social Security tax on payroll is $5.2 million, with $2.6 million reflected in Other liabilities current and $2.6 million in Other long-term liabilities in the CH Energy Group and Central Hudson Balance Sheets.

Reconciliation - CH Energy Group

The following is a reconciliation 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 (In Thousands):

	Year Ended December 31, 2020	2019	2018
Net income	$ 69,103	$ 64,566	$ 57,543
Current federal income tax (benefit)expense	(20)	(886)	6,123
Current state income tax (benefit)expense	100	(90)	1,007
Deferred federal income tax expense	9,930	10,957	4,560
Deferred state income tax expense	5,252	4,753	3,394
Income before income taxes	$ 84,365	$ 79,300	$ 72,627
Computed federal tax at 21%	$ 17,717	$ 16,653	$ 15,252
State income tax net of federal tax benefit	4,224	3,797	3,494
Amortization of protected deferred tax liability[1]	(4,339)	(3,983)	(3,716)
State income tax prior period adjustment	4	(113)	(17)
Depreciation flow-through	(706)	466	2,649
Cost of removal	(1,926)	(1,910)	(1,690)
Other	288	(176)	(888)
Total income tax expense	$ 15,262	$ 14,734	$ 15,084
Effective tax rate - federal	11.7%	12.7%	14.7%
Effective tax rate - state	6.4%	5.9%	6.1%
Effective tax rate - combined	18.1%	18.6%	20.8%

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

For the year ended December 31, 2020, the combined effective tax rate for CH Energy Group is lower than the statutory rate due to tax normalization rules and the timing of flow through tax items related to capital expenditures.

For the year ended December 31, 2019, the lower combined effective tax rate was driven by the reduction in the federal income tax rate from 35% to 21%, in accordance with the Tax Cuts and Jobs Act, and the impact of tax normalization rules.

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,	
	2020	2019
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 1,615	$ 1,991
Plant-related	6,812	7,152
Tax reform - protected deferred tax liability	48,688	50,249
Pension Costs	1,135	362
Income taxes refundable through future rates	7,294	6,041
OPEB costs	1,067	3,108
NYS Net Operating Loss ("NOL") carryforwards	4,495	495
Clean Energy Fund	14,451	18,836
Rate moderator	5,758	9,028
Contributions in aid of construction	9,429	8,945
Directors and officers deferred compensation	13,766	12,557
RDM	4,781	2,147
Fast charging infrastructure	1,339	1,198
Deferred payroll taxes	1,361	-
Low income bill program	1,234	514
Other	4,459	3,026
Accumulated Deferred Income Tax Asset	$ 127,684	$ 125,649
Accumulated Deferred Income Tax Liability:		
Depreciation	$ 243,015	$ 226,657
Repair allowance	4,143	4,367
Change in tax accounting for repairs	92,420	85,523
Income taxes recoverable through future rates	13,540	12,949
Tax reform - unprotected deferred tax asset	3,519	3,519
Cost of removal	4,981	4,993
Deferred SIR costs	2,474	1,493
Demand management programs	2,884	2,809
Purchased electric costs	907	2,094
Delayed rate increase	1,201	-
Purchased natural gas costs	1,164	1,067
Storm costs	5,202	2,985
RAM	4,517	4,370
Other	6,642	3,906
Accumulated Deferred Income Tax Liability	$ 386,609	$ 356,732
Net Deferred Income Tax Liability	$ 258,925	$ 231,083

Reconciliation – Central Hudson

The following is a reconciliation between the amount of federal income tax computed on income before taxes at the statutory rate and the amount reported in Central Hudson's Statement of Income (In Thousands):

	Year Ended December 31, 2020	2019	2018
Net income	$ 69,141	$ 64,862	$ 58,181
Current federal income tax (benefit)expense	(18)	(889)	8,546
Current state income tax (benefit)expense	-	(189)	1,117
Deferred federal income tax expense	9,952	10,462	2,334
Deferred state income tax expense	5,211	4,884	3,220
Income before income taxes	$ 84,286	$ 79,130	$ 73,398
Computed federal tax at 21%	$ 17,700	$ 16,617	$ 15,413
State income tax net of federal tax benefit	4,117	3,898	3,414
Amortization of protected deferred tax liability[(1)]	(4,339)	(3,983)	(3,716)
State income tax prior period adjustment	-	(189)	12
Depreciation flow-through	(706)	466	2,649
Cost of removal	(1,926)	(1,910)	(1,690)
Other	299	(631)	(865)
Total income tax expense	$ 15,145	$ 14,268	$ 15,217
Effective tax rate - federal	11.8%	12.1%	14.8%
Effective tax rate - state	6.2%	5.9%	5.9%
Effective tax rate - combined	18.0%	18.0%	20.7%

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

For the year ended December 31, 2020, the combined effective tax rate for Central Hudson is lower than the statutory rate due to tax normalization rules. For the year ended December 31, 2019, the lower combined effective tax rate was driven by the reduction in the federal income tax rate from 35% to 21%, and the impact of tax normalization rules.

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

	December 31, 2020	2019
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 1,615	$ 1,991
Plant-related	6,812	7,152
Tax reform - protected deferred tax liability	48,688	50,249
Pension costs	1,135	362
Income taxes refundable through future rates	7,294	6,041
OPEB costs	1,067	3,108
NYS NOL carryforwards	4,537	541
Clean Energy Fund	14,451	18,836
Rate moderator	5,758	9,028
Contributions in aid of construction	9,429	8,945
Directors and officers deferred compensation	12,866	11,605
RDM	4,781	2,147
Fast charging infrastructure	1,339	1,198
Deferred payroll taxes	1,361	-
Low income bill program	1,234	514
Other	4,390	2,878
Accumulated Deferred Income Tax Asset	$ 126,757	$ 124,595

Accumulated Deferred Income Tax Liability:				
Depreciation	$	242,572	$	226,082
Repair allowance		4,143		4,367
Change in tax accounting for repairs		92,420		85,523
Income taxes recoverable through future rates		13,540		12,949
Tax reform - unprotected deferred tax asset		3,519		3,519
Cost of removal		4,981		4,993
Deferred SIR costs		2,474		1,493
Demand management programs		2,884		2,809
Purchased electric costs		907		2,094
Delayed rate increase		1,201		-
Purchased natural gas costs		1,164		1,067
Storm costs		5,202		2,985
RAM		4,517		4,370
Other		5,563		3,081
Accumulated Deferred Income Tax Liability	$	385,087	$	355,332
Net Deferred Income Tax Liability	$	258,330	$	230,737

NOTE 6 – Investments in Unconsolidated Affiliates

In April 2019, National Grid and Transco were awarded the Segment B portion of one of its proposals related to the AC 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. Transco will be 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. As of December 31, 2020, CHET has made capital contributions of $1.4 million to Transco to fund a portion of the Segment B project costs. At December 31, 2020 and 2019, CHET's investment in Transco was approximately $9.2 million and $7.9 million, respectively.

In November 2018, the Transco limited liability company agreement was amended (“Transco Amendment”) to allow Transco to pursue additional projects that might come out of 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.

During 2020, CHEC had equity investments in various limited partnerships, one of which held investments in energy sector start-up companies. This equity investment was terminated and liquidated at its approximate book value during 2020. The value of CHEC's equity investments at December 31, 2020 and 2019 was approximately $0.2 million and $1.3 million, respectively. The remaining investment at December 31, 2020 is not considered to be a part of the core business.

NOTE 7 – Research and Development

Central Hudson’s R&D expenditures were $3.7 million in 2020, $3.5 million in 2019 and $3.3 million in 2018. 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, 2020, 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 four to nine years and communication tower space with remaining terms of approximately two to 16 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, 2020	December 31, 2019
Operating Lease Assets	Other Assets	$ 3,586	$ 4,161
Current Operating Lease Liabilities	Other Current Liabilities	$ 345	$ 542
Noncurrent Operating Lease Liabilities	Other Liabilities	3,281	3,626
Total Lease Liabilities		$ 3,626	$ 4,168

Operating and variable lease costs, as well as short-term lease cost for the years ended December 31, 2020 and 2019 were not material to CH Energy Group or Central Hudson's results of operations. Operating lease costs for the year ended December 31, 2018 were not material to CH Energy Group or Central Hudson's results of operations.

As of December 31, 2020, CH Energy Group and Central Hudson had the following minimum future maturities of operating lease liabilities (In Thousands):

Year Ending December 31,	Operating Leases
2021	$ 457
2022	460
2023	465
2024	423
2025	385
Thereafter	2,097
Total Lease Payments	4,287
Less: Imputed Interest	661
Present Value of Lease Liabilities	3,626
Less: Current Portion	345
Total Non-Current Lease Liabilities	$ 3,281

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

	December 31, 2020	December 31, 2019
Weighted-Average Remaining Lease Term (years)	9.7	10.0
Weighted-Average Discount Rate	3.26%	3.27%

NOTE 9 – Short-Term Borrowing Arrangements

Committed Credit Facilities

On July 10, 2015, CH Energy Group entered into a Third Amended and Restated Credit Agreement with four commercial banks. The credit commitment of the banks under the agreement was $50 million with a maturity date of July 10, 2020. Due to low demand for cash and the ability to receive funding from either dividends or equity capital contributions, CH Energy Group did not replace this credit agreement upon its maturity.

On March 13, 2020, Central Hudson entered into a $200 million, five-year revolving credit agreement with five commercial banks to replace the agreement that was set to expire on October 15, 2020. Proceeds received from the new revolving credit agreement are to be 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 the total funded debt to total capital shall not exceed 0.65 to 1.00. The credit agreement is also subject to certain restrictions and conditions, including there will be no event of default, and subject to certain exceptions, Central Hudson will not sell, lien, or otherwise encumber its assets and enter into certain transactions including those 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 facilities. At December 31, 2020, Central Hudson is in compliance with all financial debt covenants.

At December 31, 2020 and December 31, 2019 there were no amounts outstanding under the committed credit arrangements for CH Energy Group or Central Hudson.

Uncommitted Credit

At December 31, 2020, Central Hudson had uncommitted short-term credit arrangements with two commercial banks totaling $30 million. At December 31, 2019, Central Hudson had uncommitted short-term credit arrangements with three commercial banks totaling $40 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.

At December 31, 2020, CH Energy Group and Central Hudson had $15 million in borrowings outstanding under Central Hudson's uncommitted credit agreements with an effective weighted average interest rate of 0.9%. There were no outstanding borrowings for CH Energy Group or Central Hudson under the uncommitted credit agreements at December 31, 2019.

NOTE 10 – Capitalization – Common and Preferred Stock

Capital Contributions

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.

During 2019, CH Energy Group received capital contributions of $29.5 million from FortisUS, and Central Hudson received capital contributions of $11.0 million from its parent CH Energy Group. Additionally during 2019, CHET received a $1.1 million capital contribution from its parent CH Energy Group.

During 2018, CH Energy Group received capital contributions of $37.0 million from FortisUS, and Central Hudson received capital contributions of $11.5 million from CH Energy Group. There were no capital contributions made to CHET during 2018.

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 $67.0 million and $61.5 million in dividends to CH Energy Group for the periods ended December 31, 2020 and 2019, 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.

In 2020, CH Energy Group did not pay any dividends to FortisUS, the sole shareholder of CH Energy Group. In 2019 and 2018, the Board of Directors of CH Energy Group declared and paid dividends of $16.5 million and $22.0 million, respectively, to FortisUS.

Central Hudson did not pay any dividends to its parent CH Energy Group in 2020, 2019 and 2018.

CHET did not pay dividends to its parent CH Energy Group during 2020. CHET declared and paid dividends of $0.9 million and $2.2 million to its parent CH Energy Group during 2019 and 2018, respectively. CHEC did not pay any dividends to its parent CH Energy Group during 2020 and 2019. CHEC paid dividends to its parent CH Energy Group of $0.3 million during 2018.

Preferred Stock

Other than one share of Junior Preferred Stock, Central Hudson had no outstanding preferred stock as of December 31, 2020 and 2019.

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):

		December 31, 2020		December 31, 2019	
Series	Maturity Date	Principal	Unamortized Debt Issuance Costs	Principal	Unamortized Debt Issuance Costs
Central Hudson:					
Promissory Notes:					
2006 Series E (5.76%)(4)	Nov. 17, 2031	$ 27,000	$ 188	$ 27,000	$ 206
1999 Series B(1),(2)	Jul. 01, 2034	33,700	233	33,700	251
2005 Series E (5.84%)(4)	Dec. 05, 2035	24,000	149	24,000	158
2007 Series F (5.804%)(5)	Mar. 23, 2037	33,000	225	33,000	239
2009 Series F (5.80%)(5)	Nov. 01, 2039	24,000	204	24,000	215
2010 Series A (4.30%)(6)	Sep. 21, 2020	-	-	16,000	7
2010 Series B (5.64%)(6)	Sep. 21, 2040	24,000	99	24,000	104
2010 Series G (4.15%)(6)	Apr. 01, 2021	44,150	11	44,150	57
2010 Series G (5.716%)(6)	Apr. 01, 2041	30,000	209	30,000	219
2011 Series G (3.378%)(6)	Apr. 01, 2022	23,400	37	23,400	66
2011 Series G (4.707%)(6)	Apr. 01, 2042	10,000	92	10,000	96
2012 Series G (4.776%)(6)	Apr. 01, 2042	48,000	450	48,000	471
2012 Series G (4.065%)(6)	Oct. 01, 2042	24,000	271	24,000	284
2013 Series D (4.09%)(7)	Dec. 2, 2028	16,700	83	16,700	93
2014 Series E (7),(10)	Mar. 26, 2024	30,000	66	30,000	87
2015 Series F (2.98%)(7)	Mar. 31, 2025	20,000	67	20,000	82
2016 Series G (2.16%)(8)	Sep. 21, 2020	-	-	24,000	30
2016 Series H (2.56%)(8)	Oct. 28, 2026	10,000	53	10,000	62
2016 Series I (3.63%)(8)	Oct. 28, 2046	20,000	122	20,000	126
2017 Series J (4.05%)(8)	Aug. 31, 2047	30,000	170	30,000	177
2017 Series K (4.20%)(8)	Aug. 31, 2057	30,000	176	30,000	181
2018 Series L (4.27%)(8)	Jun. 15, 2048	25,000	175	25,000	182
2018 Series M (3.99%)(8)	Oct. 28, 2026	40,000	180	40,000	212
2018 Series N (4.21%)(8)	Oct. 28, 2033	40,000	213	40,000	229
2019 Series O (3.89%)(9)	Oct. 28, 2049	50,000	269	50,000	278
2019 Series P (3.99%)(9)	Oct. 28, 2059	50,000	271	50,000	278
2020 Series Q (3.42%)(9)	May 14 2050	30,000	172	-	-
2020 Series R (3.62%)(9)	Jul. 14, 2060	30,000	174	-	-
2020 Series S (2.03%)(9)	Sep. 28, 2030	40,000	214	-	-
2020 Series T (2.03%)(9)	Nov. 17, 2030	30,000	175	-	-
Total Central Hudson		$ 836,950	$ 4,748	$ 746,950	$ 4,390
Less: Current Portion of Long-term Debt		(44,150)		(40,000)	
Central Hudson Net Long-term Debt		$ 792,800		$ 706,950	
CH Energy Group:					
Promissory Notes:					
2009 Series B (6.80%)(3)	Dec. 15, 2025	$ 10,547	$ 47	$ 12,265	$ 56
Less: Current Portion of Long-term Debt		(1,837)		(1,718)	
CH Energy Group Net Long-term Debt		$ 801,510	$ 4,795	$ 717,497	$ 4,446

(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) Variable rate notes.

On November 17, 2020, Central Hudson issued $30 million of Series T Senior Notes, with an interest rate of 2.03% per annum and a maturity date of November 17, 2030. On September 28, 2020, Central Hudson issued $40 million of Series S Senior Notes, with an interest rate of 2.03% per annum and a maturity date of September 28, 2030. On July 14, 2020, Central Hudson issued $30 million of Series R Senior Notes, with an interest rate of 3.62% per annum and a maturity date of July 14, 2060. On May 14, 2020, Central Hudson issued $30 million of Series Q Senior Notes, with an interest rate of 3.42% per annum and a maturity date of May 14, 2050. Central Hudson used the proceeds from the sale of the Senior Notes to repay $40 million of maturing debt and for general corporate purposes, including the funding of capital expansion and improvement projects and the repayment of short-term borrowings.

At December 31, 2020, 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 on March 26, 2020 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. This interest rate cap replaced a similar interest rate cap that expired on March 26, 2020. There have been no payouts on these interest rate caps during the years ended December 31, 2020 and 2019.

The principal amount of Central Hudson's outstanding 1999 Series B NYSERDA Bonds totaled $33.7 million at December 31, 2020. 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 on March 25, 2019. The rate cap has a notional amount equal to the outstanding principal amount of the Series B bonds and expires on April 1, 2022. The cap is 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 exceeds 4% for a given month. This interest rate cap replaced a similar interest rate cap that expired on April 1, 2019. Central Hudson received a payout of $0.03 million during the year ended December 31, 2020. There were no payouts on these interest rate caps during the year ended December 31, 2019.

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

In its 2018 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. See Note 4 – "Regulatory Matters" for more detail regarding the regulatory asset related to the variable rate note.

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 September 13, 2018, the PSC authorized Central Hudson to enter into new credit agreements with maturities of no more than five years and in an aggregate amount not to exceed $200 million; and commencing upon the expiration of the prior financing order on December 31, 2018, grants the authorization to issue and sell long-term debt in an aggregate amount not to exceed $425 million through December 2021.

The continuation of $200 million of credit provides liquidity to support construction forecasts, seasonality, volatile energy markets, adverse borrowing environments, and other unforeseen events. See Note 9 – "Short-Term Borrowing Arrangements" for additional information on the committed credit funding.

The approval to issue and sell $425 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 $10.5 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, 2020, 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, 2020, 60% of all active employees were not 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 accrued liability (i.e. the under-funded status) for Pension benefits was $26.8 million and $12.3 million at December 31, 2020 and 2019, respectively. The increase in Central Hudson's unfunded liability of approximately $14.5 million resulted from an increase in plan liabilities of approximately $108.2 million partially offset by a $93.7 million increase in plan assets. The increase in plan liabilities was primarily driven by a decrease in the discount rate and assumption changes resulting from an updated experience study in 2020, partially offset by an update to the mortality projection scale. The increase in plan assets was primarily driven by investment gains.

Accrued pension costs include the difference between the PBO for the Retirement Plan and the market value of the pension assets and any liability for the non-qualified SERP. The under-funded status does not reflect approximately $32.9 million and $26.5 million of SERP trust assets at December 31, 2020 and 2019.

The cumulative amount of net periodic benefit cost in excess of employer contributions at December 31, 2020 and December 31, 2019 was $25.8 million and $22.8 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 accrued liability balance, totaling ($1.1) million at December 31, 2020 and $10.5 million at December 31, 2019, 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 employee who transferred to an affiliated company, but continues to accrue benefits in Central Hudson's Retirement Plan and SERP. These amounts reported as OCI are charged to and reimbursed by the affiliated company.

The balance of Central Hudson's accrued pension costs (i.e. the under-funded status) is as follows (In Thousands):

	December 31, 2020(1)(2)	December 31, 2019(1)(2)
Accrued pension costs	$ (26,813)	$ (12,304)

(1) Includes approximately $0.2 million at December 31, 2020 and 2019 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 $1.5 million at December 31, 2020 and $1.1 million at December 31, 2019 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, 2020(1)(2)	December 31, 2019(1)(2)
Accrued pension costs prior to funding status adjustment	$ (25,751)	$ (22,836)
Funding status adjustment required	(1,062)	10,532
Accrued pension costs	$ (26,813)	$ (12,304)
Offset to funding status adjustment - regulatory (liability) assets - pension plan	$ 851	$ (11,061)
Offset to funded status adjustment - accumulated OCI, net of tax of $55 and $138, respectively	$ 156	$ 391

(1) Includes approximately $0.2 million at December 31, 2020 and 2019 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 $1.5 million at December 31, 2020 and $1.1 million at December 31, 2019 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, the value of plan assets relative to plan liabilities, regulatory considerations, interest rate assumptions and 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 were as follows (In Thousands):

	Year Ended December 31,		
	2020	2019	2018
Retirement Plan	$ -	$ -	$ 11,144
SERP	$ 6,998	$ -	$ 3,256

Retirement Plan Discount Rate

The valuation of the current and prior year PBO was determined using discount rates of 2.34% and 3.20% for December 31, 2020 and 2019, 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 $109.3 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 Rate Order includes 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. The 2018 Rate Order again authorized Central Hudson to offset a significant portion of deferred balances for pension and OPEB expense for the electric department with available deferred credit balances due to customers.

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, 2020 and 2019 is 5.09% and 5.33%, 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 2020 net periodic benefit cost by approximately $7.2 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, 2020, as well as actual asset allocations as of December 31, 2020, and December 31, 2019 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, 2020	December 31, 2019
Equity Securities	45%	50%	55%	52.4%	51.9%
Debt Securities	45%	50%	55%	45.9%	47.1%
Other[(1)]	0%	0%	10%	1.7%	1.0%

[(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.

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, 2020 and 2019, that are reported at net asset value or fair value, as indicated (Dollars in Thousands):

Investment Type	Value at 12/31/20	% of Total	Value at 12/31/19	% of Total
At Net Asset Value:				
Investment Funds - Equities	$ 433,637	52.4%	$ 380,919	51.9%
Investment Funds - Fixed Income	128,325	15.5	119,524	16.3
At Fair Value:				
Level 2:				
Cash Equivalents	12,599	1.5	6,094	0.8
Investment Funds - Fixed Income	251,767	30.4	225,965	30.8
Other Investments	1,842	0.2	1,968	0.2
	$ 828,170	100.0%	$ 734,470	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, the expected long-term rate of return on plan assets and the 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 asset (i.e. the over-funded status) for OPEB was $6.5 million and $12.5 million at December 31, 2020 and 2019, respectively. The decrease in the over-funded status of approximately $6.0 million resulted from an increase in plan liabilities of approximately $22.2 million partially offset by a $16.2 million increase in plan assets. The increase in plan liabilities was primarily driven by a decrease in the discount rate and unfavorable claims experience in 2020. The increase in plan assets was primarily driven by investment gains.

The cumulative amount of net periodic benefit cost in excess of employer contributions at December 31, 2020 and December 31, 2019 was $7.2 million and $15.0 million, respectively. The difference between these amounts and the over-funded asset balance, totaling $13.7 million at December 31, 2020 and $27.5 million at December 31, 2019 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,		
	2020	2019	2018
OPEB Plans	$ 1,081	$ 1,001	$ 1,302

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 2020	$ 805	$ (640)
Effect on year-end 2020 post-retirement benefit obligation	$ 17,600	$ (14,215)

OPEB Discount Rate

The PBO for Central Hudson's obligation for OPEB costs was determined using a discount rate of 2.32% and 3.18% for December 31, 2020 and 2019, 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 2020 would have decreased the projection of the OPEB obligation by approximately $20.1 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, 2020 and 2019 is 5.55% and 5.62%, 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 2020 net periodic benefit cost by $1.5 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 shall be 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, 2020	December 31, 2019
Equity Securities	55%	65%	75%	67.9%	66.5%
Debt Securities	25%	35%	45%	31.7%	32.6%
Other	- %	- %	- %	0.4%	0.9%

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 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 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, 2020 and 2019, that are reported at net asset value or fair value, as indicated (Dollars in Thousands):

401(h) Plan Assets

Investment Type	Market Value at 12/31/20	% of Total	Market Value at 12/31/19	% of Total
At Net Asset Value:				
Investment Funds - Equities	$ 17,080	52.4%	$ 14,667	51.9%
Investment Funds - Fixed Income	5,055	15.5	4,602	16.3
At Fair Value:				
Level 2:				
Cash Equivalents	502	1.5	235	0.8
Investment Funds - Fixed Income	9,917	30.4	8,700	30.8
Other Investments	67	0.2	76	0.2
	$ 32,621	100.0%	$ 28,280	100.0%

Union VEBA Plan Assets

Investment Type	Market Value at 12/31/20	% of Total	Market Value at 12/31/19	% of Total
At Fair Value:				
Level 1:				
Cash Equivalents	$ 549	0.4 %	$ 1,047	0.9 %
Investment Funds - Equities	88,914	67.9	79,311	66.5
Investment Funds - Fixed Income	41,554	31.7	38,820	32.6
	$ 131,017	100.0 %	$ 119,178	100.0 %

Detail of the change in Central Hudson's Pension and OPEBs' benefit obligations, fair value of plan assets and funded status as of and for the period ended December 31, 2020 and 2019 is as follows (In Thousands):

	Pension Benefits(1)		Other Post Retirement Benefits	
	2020	2019	2020	2019
Change in Benefit Obligation:				
Benefit Obligation at beginning of year	$ 746,774	$ 653,385	$ 134,943	$ 123,867
Service cost	13,453	11,244	1,671	1,528
Interest cost	23,688	27,123	4,193	5,059
Participant contributions	-	-	1,234	1,121
Benefits paid	(33,818)	(33,020)	(7,676)	(7,153)
Actuarial loss	104,886	88,042	22,776	10,521
Benefit Obligation at end of year	$ 854,983	$ 746,774	$ 157,141	$ 134,943
Change in Value of Plan Assets:				
Fair Value of Plan Assets at beginning of year	$ 734,470	$ 619,570	$ 147,458	$ 124,725
Actual return on plan assets	128,554	148,899	21,401	27,940
Employer contributions	1,131	1,051	1,081	1,001
Participant contributions	-	-	1,234	1,121
Benefits paid	(33,818)	(33,020)	(7,676)	(7,153)
Other	(2,167)	(2,030)	140	(176)
Fair Value of Plan Assets at end of year	$ 828,170	$ 734,470	$ 163,638	$ 147,458
Funded Status at end of year	$ (26,813)	$ (12,304)	$ 6,497	$ 12,515

(1) The plan assets as presented in this chart do not include approximately $32.9 million and $26.5 million of SERP trust assets at December 31, 2020 and 2019.

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	
	2020	2019	2020	2019
Amounts Recognized on Balance Sheet:				
Noncurrent assets	$ -	$ -	$ 6,497	$ 12,515
Current liabilities	(1,473)	(1,076)	-	-
Noncurrent liabilities	(25,340)	(11,228)	-	-
Funded Status at end of year	$ (26,813)	$ (12,304)	$ 6,497	$ 12,515
Regulatory asset:				
Net actuarial gain	$ (1,109)	$ (13,565)	$ (11,435)	$ (24,710)
Prior service costs (credit)	$ 2,171	$ 2,504	$ (2,303)	$ (2,763)
Other comprehensive income:				
Net actuarial loss, net of tax	$ 39	$ 158	$ 1	$ -
Prior service costs, net of tax	$ 117	$ 233	$ 4	$ 8

(1) The funded status in this chart does not reflect approximately $32.9 million and $26.5 million of SERP trust assets at December 31, 2020 and 2019.

Central Hudson's net periodic benefit costs for its Pension and OPEB plans for the periods ended December 31, 2020 and 2019 are as follows (In Thousands):

	Pension Benefits		Other Post Retirement Benefits	
	2020	2019	2020	2019
Components of Net Periodic Benefit Cost:				
Service cost	$ 13,453	$ 11,244	$ 1,671	$ 1,528
Interest cost	23,688	27,123	4,193	5,059
Expected return on plan assets	(35,346)	(31,101)	(7,941)	(6,778)
Amortization of prior service cost (credit)	647	664	(456)	(2,691)
Amortization of recognized actuarial net (gain)/loss	1,605	4,391	(3,916)	(3,138)
Net Periodic (Benefit) Cost	$ 4,047	$ 12,321	$ (6,449)	$ (6,020)

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	
	2020	2019	2020	2019
Other Changes in Plan Assets and Benefit Obligation Recognized in Regulatory Assets/Liabilities:				
Net (gain)/loss	$ 13,846	$ (27,726)	$ 9,359	$ (10,174)
Amortization of actuarial net (loss) gain	(1,605)	(4,391)	3,916	3,138
Amortization of prior service (cost) credit	(647)	(664)	456	2,691
Total recognized in regulatory asset	$ 11,594	$ (32,781)	$ 13,731	$ (4,345)
Total recognized in net periodic benefit cost and regulatory asset	$ 15,641	$ (20,460)	$ 7,282	$ (10,365)

Weighted-average assumptions used to determine benefit obligations:				
Discount rate	2.34%	3.20%	2.32%	3.18%
Rate of compensation increase (average)	3.90%	4.00%	3.90%	4.00%
Measurement date	12/31/20	12/31/19	12/31/20	12/31/19
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31:				
Discount rate	3.20%	4.20%	3.18%	4.19%
Expected long-term rate of return on plan assets	5.09%	5.33%	5.55%	5.62%
Rate of compensation increase (average)	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
Health care cost trend rate assumed for next year	N/A	N/A	5.52%	5.84%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2038	2038
Pension plans with accumulated benefit obligations in excess of plan assets:				
Projected Benefit Obligation	$ 854,983	$ 746,774	N/A	N/A
Accumulated Benefit Obligation	$ 795,099	$ 692,347	N/A	N/A
Fair Value of Plan Assets	$ 828,170	$ 734,470	N/A	N/A

(1) The fair value of plan assets presented in this chart does not include approximately $32.9 million and $26.5 million of SERP trust assets at December 31, 2020 and 2019.

Estimated net loss of $2.5 million and prior service cost of $0.5 million for the defined benefit pension plans will be amortized from regulatory asset and OCI into net periodic benefit cost over the next fiscal year. Estimated net gain of $2.6 million and prior service credit of $0.5 million for the other defined benefit post-retirement plans will be amortized from regulatory liability and OCI into net periodic benefit cost over the next fiscal year. The amount of transitional obligation to be amortized from regulatory liabilities 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)]
2021	$ 37,621	$ 7,307	$ 6,717
2022	38,778	7,668	7,065
2023	39,170	7,967	7,351
2024	39,807	8,197	7,564
2025	40,492	8,305	7,649
Next five years	210,074	43,470	39,823

(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, 2020, 2019 and 2018 were $5.6 million, $5.2 million, and $4.9 million, respectively. Central Hudson also provided an additional contribution of 4% for 2020, 2019 and 2018 to the 401(k) plan of annualized base salary for eligible employees who do not qualify for Central Hudson’s Retirement Income Plan.

NOTE 13 – Equity-Based Compensation

Share Unit Plan Units

In January 2020, officers of CH Energy Group and Central Hudson were granted 19,912 Units under the 2020 Fortis Restricted Share Unit Plan ("2020 RSUP"), representing a portion of the officers' long-term incentives. The issued 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 January 2020, officers of Central Hudson were granted 25,311 Units under the Central Hudson 2020 Share Unit Plan ("2020 SUP"), representing a portion of the officers' long-term incentives. The issued 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. Each 2020 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 the 2020 SUP Unit grant. Each 2020 SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In January 2020, CH Energy Group granted 21,770 Units to an officer of CH Energy Group under a 2020 Share Unit Plan ("2020 PSUP"). The issued 2020 PSUP Units granted are performance based and vest upon achievement of specified performance goals over the applicable three-year performance period. Each 2020 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 2020 PSUP Unit grant. Each 2020 PSUP 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 ("2019 PSUP") in 2019, the ("2018 PSUP") in 2018, and in 2017 the ("2017 PSUP"), (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 2019 ("2019 SUP"), the 2018 ("2018 SUP"), and the 2017 ("2017 SUP") Share Unit Plans, collectively the ("SUP plans"); representing the officers' long-term incentives. Two-thirds of the SUP Units granted under the SUP plans 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 SUP plans are time-based and vest at the end of the respective three-year period without regard to performance. For all grants issued, 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 2017 PSUP and 2017 SUP Plans vested and were paid out during the first quarter of 2020.

CH Energy Group:			Grant Date	Time Based		Performance Based	
	Grant Date		Fair Value	Granted	Outstanding[6]	Granted	Outstanding[6]
2020 RSUP[5]	January 1, 2020	$	41.55	7,257	7,523	-	-
2020 PSUP[5]	January 1, 2020	$	41.55	-	-	21,770	22,569
2019 PSUP	January 1, 2019	$	33.10	8,838	9,495	26,514	28,483
2018 PSUP	January 1, 2018	$	36.59	-	-	29,514	32,998
2017 PSUP[1]	January 1, 2017	$	30.85	-	-	30,085	-

Central Hudson:			Grant Date	Time Based		Performance Based	
	Grant Date		Fair Value	Granted	Outstanding[2][6]	Granted	Outstanding[2][6]
2020 RSUP[5]	January 1, 2020	$	41.55	12,655	13,120	-	-
2020 SUP[5]	January 1, 2020	$	41.55	-	-	25,311	26,240
2019 SUP[4]	January 1, 2019	$	33.10	15,691	13,404	31,383	31,533
2018 SUP[3]	January 1, 2018	$	36.59	16,337	14,683	32,675	33,511
2017 SUP[1]	January 1, 2017	$	30.85	18,359	-	36,717	-

[1] In the first quarter of 2020, 58,145 units under the 2017 SUP and 33,633 units under the 2017 PSUP vested and were paid out at $40.15 per unit for a total of approximately $5.1 million.
[2] In the second quarter of 2019, 3,337 2017 SUP units, 2,814 2018 SUP units, and 3,075 2019 SUP units were forfeited following the resignation of an Officer.
[3] In the third quarter of 2020, per the 2018 SUP agreement, time based units were paid out related to Officer retirements at 859 shares at $42.93 per unit and 1,140 shares at $44.91 per unit.
[4] In the third quarter of 2020, per the 2019 SUP agreement, time based units were paid out related to Officer retirements at 942 shares at $39.57 per unit and 1,336 shares at $41.39 per unit.
[5] 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.
[6] Includes notional dividends accrued as of December 31, 2020.

Compensation Expense

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

	Year Ended December 31,					
	2020		2019		2018	
CH Energy Group [1]	$	2,434	$	3,023	$	1,299
Central Hudson [1]	$	2,435	$	3,012	$	1,299

[1] Included in compensation expense for 2018 is a reduction to expense resulting from a transfer of a former Central Hudson officer who is retirement eligible to an affiliated company.

The liabilities associated with the 2020 RSUP, and the annual 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 2020 RSUP, and the annual 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, 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, 2020 and 2019, 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 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 that includes Renewable Energy Credits ("RECs") and Zero-Emissions Credit ("ZECs") requirements. Beginning in 2017, LSEs, which include Central Hudson, are required to obtain RECs and ZECs in amounts determined by the PSC. LSEs may satisfy their REC obligation by either purchasing RECs acquired through central procurement by NYSERDA, by self-supply through direct purchase of tradable RECs, through value stack payments, or by making alternative compliance payments. Through March 31, 2021 LSEs will purchase ZECs from NYSERDA at tranche prices approved by the PSC based on qualifying in-state nuclear plant output and Central Hudson's full-service customer New York Control Area load-ratio share. Starting April 1, 2020, Central Hudson's obligation is comprised of an administratively determined ZEC price, Central Hudson's monthly load volume, as defined by NYISO billing data and a load modifier adjustment factor. The actual obligation will be determined and is contingent upon actual load served. At December 31, 2020, based on Central Hudson's estimated annual load to be served through March 31, 2021, the total obligation to procure ZECs is estimated to be approximately $2.4 million. Currently, the requirement to procure ZECs will continue based upon Central Hudson's future load served to its customers through 2029. The current obligation to procure RECs is defined as a percentage of load served in the state through December 31, 2023 and is estimated for Central Hudson to be approximately $9.5 million. NYSERDA will be introducing indexed RECs beginning January 1, 2021. REC pricing will change each quarter (weighted average of vintage fixed and new indexed RECs) and the Alternative Compliance Payment will be set in advance of the compliance year. These future costs are recoverable from customers through electric cost adjustment mechanisms.

Natural Gas Commitments

Central Hudson meets its natural gas capacity and supply obligations through firm natural gas supply contracts with energy providers for the purchase of natural gas including peak demand supply. Gas supply contracts are generally short term in nature. Central Hudson also enters into contracts associated with natural gas interstate pipeline capacity, and supply contracts for storage of natural gas.

Commitments

The following is a summary of commitments for CH Energy Group and its affiliates as of December 31, 2020 (In Thousands):

		Projected Payments Due By Period						
		Year Ending 2021	Year Ending 2022	Year Ending 2023	Year Ending 2024	Year Ending 2025	Thereafter	Total
Recorded Contractual Obligations:								
Operating Leases		$ 457	$ 460	$ 465	$ 423	$ 385	$ 2,097	$ 4,287
Repayments of Long-Term Debt		45,987	25,364	2,100	32,245	22,401	719,400	847,497
Stock-based compensation obligations		3,416	3,243	1,880	-	-	-	8,539
Unrecorded Contractual Obligations:								
Purchased Electric Contracts	(1)	23,250	8,272	1,150	150	150	452	33,424
Energy Credit Purchase Agreements		3,625	3,356	4,906	-	-	-	11,887
Purchased Natural Gas Contracts	(1)	28,135	17,074	16,333	12,711	5,591	16,168	96,012
Interest Obligations on Long-Term Debt		32,447	31,009	30,478	30,054	29,507	483,331	636,826
Total		$ 137,317	$ 88,778	$ 57,312	$ 75,583	$ 58,034	$ 1,221,448	$ 1,638,472

(1) Purchased electric and purchased natural gas costs 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, 2020 (In Thousands):

		Projected Payments Due By Period						
		Year Ending 2021	Year Ending 2022	Year Ending 2023	Year Ending 2024	Year Ending 2025	Thereafter	Total
Recorded Contractual Obligations:								
Operating Leases		$ 457	$ 460	$ 465	$ 423	$ 385	$ 2,097	$ 4,287
Repayments of Long-Term Debt		44,150	23,400	-	30,000	20,000	719,400	836,950
Stock-based compensation obligations		1,888	2,143	1,450	-	-	-	5,481
Unrecorded Contractual Obligations:								
Purchased Electric Contracts	(1)	23,250	8,272	1,150	150	150	452	33,424
Energy Credit Purchase Agreements		3,625	3,356	4,906	-	-	-	11,887
Purchased Natural Gas Contracts	(1)	28,135	17,074	16,333	12,711	5,591	16,168	96,012
Interest Obligations on Long-Term Debt		31,761	30,450	30,054	29,775	29,385	483,331	634,756
Total		$ 133,266	$ 85,155	$ 54,358	$ 73,059	$ 55,511	$ 1,221,448	$ 1,622,797

(1) Purchased electric and purchased natural gas costs 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 2021, Central Hudson made a contribution of $0.8 million to the 401(h) Plan to fund the management OPEB liabilities, in accordance with Central Hudson's OPEB policy and strategy. No funding contributions are expected to be made to the Retirement and VEBA Plans for the 2020 Plan years. See Note 19 – "Subsequent Events" for details of the January payment.

Supplemental Executive Retirement Plan

As a result of the acquisition of CH Energy Group, Inc. by Fortis on June 27, 2013, 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. Central Hudson is expected to make a contribution to the SERP for 2020 of $8.1 million in March 2021, resulting in a funding status that achieves 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. In December 2014, Transco filed an application with the FERC for the recovery through a formula rate, of the cost of and a return on five high voltage transmission projects totaling $1.7 billion. CH Energy Group guaranteed to Transco the payment of CHET's maximum commitment of $182 million for these five projects, which is the maximum budgeted amount for these projects at 100% equity. On July 16, 2020, CH Energy Group's parental guarantee to Transco was adjusted from $182 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, 2020, CHET's investment in Transco was approximately $9.2 million and 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, 2020, Central Hudson has accrued $74.9 million with respect to all SIR activities, including operation, maintenance and monitoring costs ("OM&M"), of which $21.0 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, 2020	Estimated spend in the next twelve months
Investigation	# 9 - Little Britain Road (1)	$ 2.2	$ 0.2
Remedial Alternatives Analysis		-	-
Remedial Design		-	-
Remediation	#5 - North Water Street (2)	68.1	20.5
Post-Remediation Monitoring	#2 - Newburgh Areas A, B & C #3 - Laurel Street #4 - Catskill #6 - Kingston #8 - Eltings Corners		
	Subtotal	4.6	0.3
No Action Required	#1 - Beacon #7 - Bayeaux Street	-	-
Total		$ 74.9	$ 21.0

There were no significant updates during the year ended December 31, 2020 or changes in the nature and amounts of Central Hudson's contingencies related to environmental matters, except as noted below.

- **(1) Remedial Investigation in Progress - Site #9 – Little Britain Road**
  - The New York State DEC issued a letter of Completeness in August 2018, and a Brownfield Cleanup Agreement was fully executed with the DEC in March 2019.

- A Sub-slab Depressurization System ("SSDS") Evaluation Work Plan to evaluate the existing system and mitigate the potential for vapor intrusion into the building located at this site was approved by the DEC in May 2019. Sampling of the SSDS commenced and was completed in mid-2020 and results were submitted to the DEC and New York State Department of Health ("NYSDOH"). An operation and maintenance ("O&M") plan for the SSDS that includes routine inspections and air testing was approved by the DEC and NYSDOH in August 2020. Quarterly O&M events commenced on the SSDS in October 2020.
- The results from the most recent groundwater monitoring event were submitted to the DEC in October 2020 and were consistent with historic trends.
- A summary report of investigation activities to further delineate impacts to the soil and groundwater at the site with the installation of several groundwater monitoring wells was approved in March 2019. Based on the results of this investigation, higher concentrations of contaminants were encountered with a distribution more widespread horizontally and vertically than previously observed. On July 22, 2019, the DEC requested additional investigation to be performed. A Remedial Investigation Work Plan was approved in September 2020 and estimated costs to complete the investigation have been accrued for work that is anticipated to commence in the spring of 2021. The results of the additional investigative procedures and any potential additional remedial activities required, if any, cannot be predicted at this time.

➢ **(2) Remediation in Progress - Site #5 – North Water Street**

- As a result of several issues relating to fabrication, installation and the inability to operate the moon pool as designed, remedial activities were halted in December 2019.
- A Moon Pool Performance Root Cause Analysis Summary was submitted to the DEC for review on February 18, 2020 and a conference call was held on March 12, 2020 to discuss the analysis of the failures that developed with the moon pool as well as a recommendation that the moon pool containment and mechanical dredging approach was no longer technically feasible.
- The DEC requested that Central Hudson proceed to develop a design and work plan for piloting hydraulic dredging for source removal, including providing enhanced water quality monitoring. The DEC has continued to emphasize a path forward that includes the removal of source material versus an alternative remedial approach (e.g. capping).
- An assessment of a high-solids hydraulic dredging remedial alternative including predictive cost modeling for a pilot test and full-scale remediation was performed with an estimated total project cost range from $71 million to $114 million.
- Based on the above discussions and analyses performed, Central Hudson revised its estimate of the total remediation costs associated with this site during the first quarter of 2020 to remove "moon pool" mechanical dredging as a viable solution and record the low end of the range of projected costs for remediation activities at this site.
- In September 2020, the DEC approved the Hydraulic Dredging Pilot Test 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 December 2020.
- 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). Data was compiled related to production rates in each area, impacts on sheening and the ability to contain it. Two methods of dewatering were effectively utilized during the pilot study and the production rates and capabilities of each are now being further analyzed.

- Central Hudson believes the remaining costs to complete the analysis of data from the pilot study and the full scale-remediation could range from $61 million to $104 million. The procedures performed during the pilot did not provide any indication or evidence to support a change in the estimated range or that any point within the range is a better estimate at this time. As such, the accrual as of December 31, 2020 continues to be the low end of the range of projected costs for remediation activities at this site, plus estimated OM&M activities following remediation. The estimated costs will continue to be updated as further testing is performed and assumptions are refined.
- The estimated spending as of December 31, 2020 for the next 12 months of approximately $20.5 million is based primarily on the initiation of a full-scale hydraulic pilot test anticipated during the fall of 2021.

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 2018 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 2018 Rate Order includes cash recovery of approximately $25.7 million during the three-year rate plan period ending June 30, 2021, with $21.1 million recovered through December 31, 2020.
- The total spent related to site investigation and remediation for the years ended December 31, 2020 and 2019 was approximately $11.2 million and $9.0 million, respectively.
- The regulatory asset balance including carrying charges as of December 31, 2020 and 2019 was $84.4 million and $62.7 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 year ended December 31, 2020 and $0.2 million of insurance recoveries for the year ended December 31, 2019. 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, 2020, of the 3,382 asbestos cases brought against Central Hudson, 1,169 remain pending. Of the cases no longer pending against Central Hudson, 2,051 have been dismissed or discontinued without payment by Central Hudson and Central Hudson has settled 162 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 investments in limited partnerships, 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 2018 Rate Order is 80% for electric and 20% for natural gas.

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2020				
	Segments		Other		
	Central Hudson		Businesses		
		Natural	and		
	Electric	Gas	Investments	Eliminations	Total
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

CH Energy Group Segment Disclosure
(In Thousands)

	Year Ended December 31, 2019				
	Segments		Other		
	Central Hudson		Businesses		
		Natural	and		
	Electric	Gas	Investments	Eliminations	Total
Revenues from external customers	$ 529,460	$ 162,203	$ -	$ -	$ 691,663
Intersegment revenues	46	299	-	(345)	-
Total operating revenues	529,506	162,502	-	(345)	691,663
Energy supply costs	142,131	49,729	-	(345)	191,515
Operating expenses	272,357	67,121	208	-	339,686
Depreciation and amortization	45,204	14,161	-	-	59,365
Operating income (loss)	69,814	31,491	(208)	-	101,097
Other income, net	8,892	2,464	1,299	-	12,655
Interest charges	24,851	8,680	921	-	34,452
Income before income taxes	53,855	25,275	170	-	79,300
Income tax expense	10,151	4,117	466	-	14,734
Net Income (Loss) Attributable to CH Energy Group	$ 43,704	$ 21,158	$ (296)	$ -	$ 64,566
Segment Assets at December 31, 2019	$ 1,730,543	$ 669,656	$ 18,349	$ (709)	$ 2,417,839
Capital Expenditures	$ 162,023	$ 76,694	$ -	$ -	$ 238,717

CH Energy Group Segment Disclosure
(In Thousands)

	Year Ended December 31, 2018				
	Segments		Other		
	Central Hudson		Businesses		
		Natural	and		
	Electric	Gas	Investments	Eliminations	Total
Revenues from external customers	$ 558,533	$ 166,098	$ -	$ -	$ 724,631
Intersegment revenues	39	328	-	(367)	-
Total operating revenues	558,572	166,426	-	(367)	724,631
Energy supply costs	191,501	63,967	-	(367)	255,101
Operating expenses	254,494	60,539	911	-	315,944
Depreciation and amortization	41,749	12,745	-	-	54,494
Operating income (loss)	70,828	29,175	(911)	-	99,092
Other income, net	3,764	797	1,156	-	5,717
Interest charges	23,259	7,907	1,016	-	32,182
Income (loss) before income taxes	51,333	22,065	(771)	-	72,627
Income tax expense (benefit)	9,612	5,605	(133)	-	15,084
Net Income (Loss) Attributable to CH Energy Group	$ 41,721	$ 16,460	$ (638)	$ -	$ 57,543
Segment Assets at December 31, 2018	$ 1,650,929	$ 582,169	$ 13,715	$ (953)	$ 2,245,860
Capital Expenditures	$ 118,598	$ 70,375	$ -	$ -	$ 188,973

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. Premiums paid for weather related instruments are amortized based on the pattern of normal purchases of electricity or natural gas over the term of the contract and any payouts earned will be recorded as a reduction of the cost.

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, 2020 are as follows:

Central Hudson	% of Requirement Hedged [1]
Electric Derivative Contracts:	0.5 million MWh
January 2021 – August 2021	30.4%
Natural Gas Derivative Contracts:	0.5 million Dth
January 2021 – March 2021	11.6%

[1] Projected coverage as of December 31, 2020.

In 2020, OTC derivative contracts covered approximately 32.1% of Central Hudson’s total electricity supply requirements as compared to 45.6% in 2019.

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, 2020, three 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, 2020 if the contingent features were triggered, are described below.

Contingent Contracts

(Dollars In Thousands)

	As of December 31, 2020		
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	1	$ (16)	$ (16)
Adequate Assurance	2	(1,752)	(1,752)
Total Central Hudson	3	$ (1,768)	$ (1,768)

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, 2020 and December 31, 2019, 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):

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	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2020[1]						
Derivative Contracts:						
Central Hudson - electric	$ -	$ -	$ -	$ -	$ -	$ -
Central Hudson - natural gas	18	-	18	14	-	4
Total CH Energy Group and Central Hudson Assets	$ 18	$ -	$ 18	$ 14	$ -	$ 4
As of December 31, 2019[1]						
Derivative Contracts:						
Central Hudson - electric	$ -	$ -	$ -	$ -	$ -	$ -
Central Hudson - natural gas	-	-	-	-	-	-
Total CH Energy Group and Central Hudson Assets	$ -	$ -	$ -	$ -	$ -	$ -

(1) Interest rate cap agreements are not shown in the above chart. As of December 31, 2020 and 2019 the fair value was $0.

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	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2020[1]						
Derivative Contracts:						
Central Hudson - electric	$ 2,104	$	$ 2,104	$ -	$ -	$ 2,104
Central Hudson - natural gas	49		49	14	-	35
Total CH Energy Group and Central Hudson Liabilities	$ 2,153	$ -	$ 2,153	$ 14	$ -	$ 2,139
As of December 31, 2019[1]						
Derivative Contracts:						
Central Hudson - electric	$ 5,542	$ -	$ 5,542	$ -	$ -	$ 5,542
Central Hudson - natural gas	720	-	720	-	-	720
Total CH Energy Group and Central Hudson Liabilities	$ 6,262	$ -	$ 6,262	$ -	$ -	$ 6,262

(1) Interest rate cap agreements are not shown in the above chart. As of December 31, 2020 and 2019 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, 2020 and 2019, 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, 2020(1)				
Assets:				
Derivative Contracts:				
Central Hudson - electric	$ -	$ -	$ -	$ -
Central Hudson - natural gas	18	18	-	-
Total CH Energy Group and Central Hudson Assets	$ 18	$ 18	$ -	$ -
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ 2,104	$ -	$ 2,104	$ -
Central Hudson - natural gas	49	49	-	-
Total CH Energy Group and Central Hudson Liabilities	$ 2,153	$ 49	$ 2,104	$ -
As of December 31, 2019(1)				
Assets:				
Derivative Contracts:				
Central Hudson - electric	$ -	$ -	$ -	$ -
Central Hudson - natural gas	-	-	-	-
Total CH Energy Group and Central Hudson Assets	$ -	$ -	$ -	$ -
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ 5,542	$ -	$ 5,542	$ -
Central Hudson - natural gas	720	720	-	-
Total CH Energy Group and Central Hudson Liabilities	$ 6,262	$ 720	$ 5,542	$ -

(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, 2020 and 2019 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, 2020, 2019 and 2018, 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,			
	2020	2019	2018	Location of Gain (Loss)
Central Hudson:				
Electricity swap contracts	$ (14,379)	$ (15,145)	$ (2,670)	Deferred purchased electric costs(1)
Natural gas swap contracts	(866)	(23)	287	Deferred purchased natural gas costs(1)
Total CH Energy Group and Central Hudson	$ (15,245)	$ (15,168)	$ (2,383)	

(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 2020, Central Hudson entered into a weather option for the period December 1, 2020 through March 31, 2021, to hedge the effect of significant variances in weather conditions on electricity costs. For Central Hudson, this transaction will impact purchased electric expense and revenue, but will not have a net income impact due to the full deferral authority over commodity costs through its electric cost adjustment charge mechanisms. The aggregate limit on the contract is $5 million. This contract will be accounted for in accordance with guidance specific to accounting for weather derivatives. The $1.3 million premium paid will be amortized to purchased electricity over the term of the contract and all payouts will be recorded as a reduction to purchased electricity in the Statements of Income. In December 2020, the $0.2 million payout earned was recorded as an offset to purchase electric cost. The unamortized premium at December 31, 2020 is approximately $1 million and is included in the "special deposits and prepayments" line item of CH Energy Group's and Central Hudson's Balance Sheets.

In 2019 and 2018, Central Hudson entered into similar weather options for the periods of December 1, 2019 through March 31, 2020 and December 1, 2018 through March 31, 2019, respectively, with an aggregate limit of $5 million per contract. Premiums paid were amortized to purchased electricity over the term of the agreements. The respective payouts earned of $0.1 million and $0.7 million on the 2019 and 2018 contracts were recorded as a reduction to purchased electricity in the Statements of Income in the first quarter of 2020 and 2019, respectively.

Based on Central Hudson's valuation model, the fair value of the weather option purchased for the December 1, 2020 through March 31, 2021 period, as of December 31, 2020 was approximately $0.5 million. The fair value of the December 1, 2019 through March 31, 2020 weather option was approximately $1.4 million as of December 31, 2019. The valuations were based on significant unobservable inputs, including short term temperature forecast and historical temperature fluctuations in winter and, as such, would be a Level 3 valuation.

Central Hudson – Natural Gas

In October 2020, Central Hudson entered into a weather option for the period December 1, 2020 through March 31, 2021, to hedge the effect of significant variances in weather conditions and price on natural gas costs. For Central Hudson, this transaction will impact purchased natural gas expense and revenue, but will not have a net income impact due to the full deferral authority over commodity costs through its natural gas cost adjustment charge mechanisms. The aggregate limit on the contract is $5 million. The terms of this contract included both a weather and natural gas price trigger. However, management believes weather was the predominant trigger for any payout that would have been earned under the contract. Therefore, this contract was accounted for in accordance with guidance specific to accounting for weather derivatives. The $1.7 million premium paid will be amortized to purchased natural gas over the term of the contract and all payouts will be recorded as a reduction to purchased natural gas in the Statement of Income. The unamortized premium at December 31, 2020 was approximately $1.3 million and is reflected in the “special deposits and prepayments” line item of CH Energy Group’s and Central Hudson’s Balance Sheets.

In 2019 and 2018, Central Hudson entered into similar weather options for the periods of December 1, 2019 through March 31, 2020 and December 1, 2018 through March 31, 2019, respectively. The aggregate limit per contract was $5 million. Premiums paid were amortized to purchased natural gas over the term of the related agreement. There was no payout earned on the 2019 contract. The payout earned of $0.5 million on the 2018 contract was recorded as a reduction to purchased natural gas in the Statements of Income during the first quarter of 2019.

Based on Central Hudson’s valuation model, the fair value of the weather options purchased for the December 1, 2020 through March 31, 2021 and December 1, 2019 through March 31, 2020 period was approximately $0.4 million as of December 31, 2020 and $2.2 million as of December 31, 2019, respectively. The valuations were based on an analysis, which includes significant unobservable inputs, specifically short-term weather forecasts, historical temperature fluctuations and correlation between daily temperature fluctuations and natural gas prices in winter and, as such, would be a Level 3 valuation.

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 in 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, 2020:				
Other Investments	$ 14,776	$ 14,776	$ -	$ -
As of December 31, 2019:				
Other Investments	$ 8,865	$ 8,865	$ -	$ -

As of December 31, 2020 and December 31, 2019, 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, 2020 and December 31, 2019, the total cash surrender value of trust-owned life insurance held by these trusts was approximately $33.1 million and $31.6 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 are 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 (typically one month or less) 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 portion (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, 2020:						
2021	$ 45,987	4.30%	$ -	-%		
2022	25,364	3.69%	-	-%		
2023	2,100	6.92%	-	-%		
2024	2,245	6.92%	30,000	1.25%		
2025	22,401	3.42%	-	-%		
Thereafter	685,700	4.27%	33,700	0.16%		
Total	$ 783,797	4.24%	$ 63,700	0.68%	$ 847,497	3.98%
Fair Value	$ 949,413		$ 63,700		$ 1,013,113	

As of December 31, 2019:						
2020	41,718	3.20%	-	-%		
2021	45,987	4.30%	-	-%		
2022	25,364	3.69%	-	-%		
2023	2,100	6.91%	-	-%		
2024	2,245	6.91%	30,000	2.98%		
Thereafter	578,101	4.58%	33,700	2.41%		
Total	$ 695,515	4.46%	$ 63,700	2.68%	$ 759,215	4.31%
Fair Value	$ 790,711		$ 63,700		$ 854,411	

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, 2020:						
2021	$ 44,150	4.19%	$ -	-%		
2022	23,400	3.42%	-	-%		
2023	-	-%	-	-%		
2024	-	-%	30,000	1.25%		
2025	20,000	3.00%	-	-%		
Thereafter	685,700	4.27%	33,700	0.16%		
Total	$ 773,250	4.21%	$ 63,700	0.68%	$ 836,950	3.94%
Fair Value	$ 937,666		$ 63,700		$ 1,001,366	
As of December 31, 2019:						
2020	40,000	3.04%	-	-%		
2021	44,150	4.19%	-	-%		
2022	23,400	3.42%	-	-%		
2023	-	-%	-	-%		
2024	-	-%	30,000	2.98%		
Thereafter	575,700	4.57%	33,700	2.41%		
Total	$ 683,250	4.42%	$ 63,700	2.68%	$ 746,950	4.27%
Fair Value	$ 777,318		$ 63,700		$ 841,018	

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. In addition, The Chazen Companies perform 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 The Chazen Companies, respectively, as follows (In Thousands):

	Year Ended December 31, 2020	2019	2018
CH Energy Group (Thompson Hine LLP)	$ 2,264	$ 2,096	$ 2,199
Central Hudson (Thompson Hine LLP)	$ 2,233	$ 2,055	$ 2,158
Central Hudson (The Chazen Companies)	$ 710	$ 829	$ 596

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.

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

	December 31, 2020	December 31, 2019
CH Energy Group[1]	Fortis	Fortis
Accounts Receivable	$ 1,350	$ 982
Accounts Payable	$ -	$ -

	December 31, 2020			December 31, 2019		
Central Hudson[1]	CHEG	Fortis	Other Affiliates	CHEG	Fortis	Other Affiliates
Accounts Receivable	$ 157	$ 25	$ 9	$ 109	$ 23	$ 4
Accounts Payable	$ 931	$ -	$ -	$ 574	$ -	$ -

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

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

	December 31, 2020		December 31, 2019		December 31, 2018	
	CHEG	Fortis[1]	CHEG	Fortis[1]	CHEG	Fortis[1]
CH Energy Group	$ -	$ 3,692	$ -	$ 3,121	$ -	$ 2,799
Central Hudson	$ 4,172	$ -	$ 3,545	$ -	$ 3,107	$ -

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

NOTE 19 – Subsequent Events

An evaluation of subsequent events was completed through February 11, 2021, 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, 2020.

On January 29, 2021, Central Hudson made a contribution of $0.8 million to the 401(h) Plan to fund the management OPEB liabilities.

MANAGEMENT'S DISCUSSION and ANALYSIS of FINANCIAL CONDITION and RESULTS of OPERATIONS
For the Year Ended December 31, 2020

This Management Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the 2020 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 partnership 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 well-diversified leader in the North American regulated electric and gas utility industry, with 2020 revenue of CAD$8.9 billion and total assets of approximately CAD$55 billion. Fortis and its subsidiaries' 9,000 employees serve 3.3 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Central Hudson purchases, sells at wholesale and retail, and distributes electricity and natural gas at retail, in portions of New York State to electric and natural gas customers and is subject to regulation by the New York Public Service Commission ("PSC" or "Commission").

Purpose and Strategy

In the fourth quarter of 2020, Central Hudson adopted a new Purpose Statement - **"Together We Power Endless Possibilities,"** 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***

CH Energy Group's strategy is to:
- Invest primarily in electric and gas transmission and distribution; and
- Maintain a financial profile that supports a credit rating for Central Hudson in the "A" category.

Human Capital Resources

Central Hudson recognizes the importance of its employees and dedicates substantial efforts toward attracting, developing and retaining individuals who exemplify the values that are the cornerstone of our Company. In 2020, Central Hudson reaffirmed our core purpose and values as outlined above. In these statements we made it clear that our people are absolutely essential to our success. As of December 31, 2020, we had 1,061 employees, with approximately 60% covered by collective bargaining ("union") agreements. In addition, we work with many outside firms to obtain additional resources to support our business. We utilize human capital resources employed by these firms to supplement our internal labor 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 believe we have good relationships with both our union and suppliers of contracted services.

Safety is of the utmost importance for our employees, and we consider safety to be 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 have been 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 an inclusive and diverse environment for all of our employees. 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 7% 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.

Strategy Execution

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 $250 million in 2020, and its five year forecast includes an average of approximately $270 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 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 its proposals 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. Transco will be 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, 2020, CHET's investment in Transco was approximately $9.2 million.

In November 2018, Transco’s limited liability company agreement was amended (“Transco Amendment”) to allow Transco to pursue additional projects that might come out of future New York Independent System Operator (“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.

Central Hudson
Business Description and Strategy

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

- Modernizing its business through electric and natural gas system investments and process improvements;
- Continuously improving its 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 is committed to a cleaner energy future by supporting New York State's energy policies and its Reforming the Energy Vision ("REV") goals and strongly believes that maintaining affordability must be part of the solution. Central Hudson is making investments in infrastructure, technologies and programs that cost-effectively reduce carbon emissions while continuing to provide reliable, resilient and affordable power 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 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 as a low-carbon option for heating and manufacturing;
- Expanding energy efficiency programs, the most cost-effective method to reduce emissions; and
- Advancing environmentally beneficial electrification, for example promoting electric vehicles and heat pumps to lower emissions from the transportation and building heating sectors.

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. Central Hudson's capital expenditures through June 2021 were approved by the PSC in the 2018 Rate Order. Central Hudson filed an electric and natural gas rate case on August 27, 2020, which included a request for continued funding of its 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 to address these risks.

COVID-19

We provide essential services to our customers and it is paramount that we keep our employees safe. The outbreak of the novel Coronavirus pandemic ("COVID-19") is an ongoing situation that has adversely impacted economic activity and business conditions on a global scale and specifically within Central Hudson's service territory. In particular, efforts to control the spread of COVID-19 have led to shutdowns of various businesses in our service territory and have required changes to our operations to mitigate potential risks and impacts to our customers and employees. Along with all major utilities in New York State, we have temporarily suspended service disconnections and finance charges for non-payment to help mitigate the economic impact of COVID-19 on our customers. Central Hudson has not experienced any significant issues with our supply chain, contractor availability or access to capital; however, we have increased our inventory levels to meet anticipated operational needs. The Company is continuing with electric and natural gas capital investments, although non-essential construction was paused for a period as mandated in the second quarter. In December, vaccines were approved by the Food & Drug Administration and are now available for select individuals as defined by New York State. Throughout the area there has been an increase in positive cases and hospitalizations. New York State has implemented a Regional Micro-Cluster Strategy and has imposed higher restrictions within certain sections of Central Hudson's service territory based on thresholds exceeded related to the region's positivity rate over the past 10 days, hospital admissions per capita over the past week, and week-over-week growth in daily admissions. There continues to be uncertainty regarding the continued progression and timing of re-opening, potential setbacks if increases in cases continue, and the full economic impact this will have on our customers and business.

Central Hudson has incurred approximately $4.0 million of pre-tax incremental operating expenses through December 31, 2020 related to costs for the sequestration of key employees to ensure the continued reliability of system operations, additional personal protective equipment and cleaning services and supplies. Central Hudson has identified approximately $3.0 million in cost reductions during the pandemic through December 31, 2020 primarily due to reduced overtime labor, contractor, training and travel expenses. Central Hudson has also increased its reserve for uncollectible accounts by $4.9 million based on a quantitative and qualitative assessment of forecasted economic conditions related to COVID-19. This assessment included a historical analysis of the relationship of write-offs to accounts receivable balances in arrears and taking into consideration certain qualitative factors of both current, and an estimated forecast of future, economic conditions including the nature and cause of this economic downturn, as well as legislative actions taken which provide relief and assistance to customers financially impacted by the COVID-19 pandemic. Additionally, Central Hudson has experienced lost revenues associated with the discontinuation of finance charges on customers' past due balances of approximately $3.7 million to date, bringing the total net impact on Central Hudson to $9.6 million on a pretax basis, or $8.4 million impact on net income to date in 2020. Barring any additional setbacks, management does not expect to incur continued incremental costs associated with sequestration of key employees. Incremental operating expenses associated with personal protective equipment and cleaning services and supplies are expected to continue for the foreseeable future, but management expects to be able to manage these incremental costs with identified cost reduction efforts.

Central Hudson is actively communicating with New York State Department of Public Service ("DPS") with regard to COVID-19 incremental costs and lost revenues and cost reductions identified through the Generic Proceeding (Case 20-M-0266). Central Hudson has also taken measures to support our customers, employees and communities impacted by the COVID-19 pandemic and to support the economic recovery in our service territory. For all its customers, Central Hudson suspended certain collection activities including terminating service for non-payment, waived finance charges, doubled its contribution to its last resort grant program and postponed scheduled rate increases. 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 also begun to reach out to customers regarding past due balances to ensure the customers are aware of certain financial assistance programs available to them and to proactively engage with them in managing these balances with deferred payment arrangements. Due to current legislation, Central Hudson cannot resume residential terminations until at least March 31, 2021. Management is monitoring the New York State, State of Emergency and will determine the appropriate time to begin additional collection efforts, including re-instating finance charges on past due balances and termination activities.

Additionally, Central Hudson's rate filing in August 2020 requesting an increase in electric and natural gas delivery rates to be effective July 1, 2021, 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 which management believes could be accomplished without impacting safety and reliability. The rate filing also included a requested deferral for COVID-19 related costs.

On June 11, 2020, the Commission established a new proceeding, to identify and address the effects of the COVID-19 pandemic on utility service in New York State. The proceeding included, but is not limited to, impacts on rate-setting, collections and termination of service, and ensuring the provision of safe and adequate service at just and reasonable rates in recognition of the ramifications from the COVID-19 pandemic. Central Hudson is providing the monthly requested information to the PSC with regards to COVID-19 lost finance charge revenues and incremental costs, including the increase in past due balances and the uncollectible reserve and cost reductions.

The total extent of COVID-19 related impacts on our results of operations is unknown at this time and is contingent upon the continued progression of the re-opening of the economy in our service territory, the ability of our customers to recover from the economic slowdown and related Federal and New York State mandates and regulatory proceedings. An extended delay or potential setback in the economic recovery of our service territory and/or material changes in governmental policy could impact the ability of our customers, contractors, suppliers and other business partners to fulfill their obligations to us, which could have a material adverse effect on our results of operations and financial condition. COVID-19 and its related impacts continues to be an evolving situation, and we will continue to monitor any developments, including regulatory or legislative mandates, affecting our workforce, our customers, contractors and suppliers, as well as our access to capital markets and the potential to recover all or a portion of these incremental costs.

Regulatory/Compliance Risks:

- Federal Energy Regulatory Commission ("FERC"): under the Federal Power Act, FERC has 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.

- North American Electric Reliability Corporation ("NERC"): Central Hudson, as owner and operator of the Bulk Electric System, is subject to potential penalties for violations of NERC Reliability Standards.

- 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 Mechanism ("RDMs") or Rate Adjustment Mechanism. 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 violations of state utility laws, regulations or orders.

- REV: Governor Cuomo and the PSC announced the commencement of its 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, the Climate Leadership and Community Protection Act ("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.

- Department of Environmental Conservation ("DEC"): Central Hudson, as owner and operator of certain hydroelectric facilities and environmental site investigation and remediation activities is subject to DEC regulations and could incur penalties for violations.

- The Pipeline and Hazardous Materials Safety Administration ("PHMSA"): Central Hudson, as owner and operator of certain natural gas transmission facilities, is subject to PHSMA regulation and could incur penalties for violations.

- NYISO: In accordance with the Market Service Tariff, Central Hudson is obligated to provide current load forecasting and generator bid requirements and could incur penalties for violations.

- United States Army Corps of Engineers: Central Hudson owns and operates certain natural gas and electric infrastructure that may cross or are located within a federally protected wetland or water body. Any operation, maintenance, construction, repair or replacement of this infrastructure is subject to certain compliance requirements and could incur penalties for non-compliance.

Operations Risks:

- 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.

- Central Hudson, as an operator of critical energy infrastructure, may face a heightened risk of cyber-attack. In the event of a cyber-attack that Central Hudson was 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.

- Another risk is the ability to effectively manage costs, which 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.

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, PCBs and coal tar have been used or produced in the course of Central Hudson' 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.

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

	Year to Date		
	2020	**2019**	**Change**
Electricity Sales (GWh)	4,969	4,963	6
Natural Gas Sales (PJ)	22.5	21.9	0.6
(In millions)			
Revenues	$ 711.9	$ 691.7	$ 20.2
Energy Supply Costs - Matched to Revenues	173.4	191.5	(18.1)
Operating Expenses - Matched to Revenues	94.6	76.8	17.8
Operating Expenses - Other	280.0	262.7	17.3
Depreciation and Amortization	66.9	59.4	7.5
Other Income, net	22.0	11.4	10.6
Interest Charges	34.7	33.5	1.2
Income Taxes	15.1	14.3	0.8
Net income	$ 69.1	$ 64.9	$ 4.2

Earnings: Despite challenges in the current year associated with the impacts of the COVID-19 pandemic, Central Hudson was able to achieve earnings growth compared to the prior year. The PSC-approved increase in delivery rates effective July 1, 2019 and July 1, 2020 provided return on additional capital invested in the business and recovery of higher operating and financing expenses. Although the delivery rate increase approved for July 1, 2020 was delayed until October 1, 2020, the associated revenue during the third quarter was recorded as an alternative revenue program and is currently being billed to and recovered from customers over the remaining period of the rate year ending June 30, 2021. Additionally, the Company recorded earnings adjustment mechanisms and earned incentives in the current year based on achieving certain targets and milestones associated with energy efficiency, reliability and customer service as provided in the 2018 Rate Order. These increases in earnings were partially offset by the impacts of the COVID-19 pandemic.

The impacts of the COVID-19 pandemic on earnings was approximately $8.4 million which included both reduced revenues and net incremental costs incurred. The reduction to revenues resulted from the discontinuation of finance charges applied to customers' past due balances beginning April 1, 2020 in recognition of the impacts of governmental mandates on Central Hudson's customers during the pandemic. Central Hudson's current rates include a RDM which provides recovery of variations in sales for 97% of its business and those customers not covered by the RDM did not experience a change in sales volume as a result of the COVID-19 pandemic. As such, there was no earnings impact associated with variations in residential and small commercial sales during the pandemic. Incremental COVID-19 related operating costs included costs associated with measures taken to ensure continued safe and reliable service provided during the initial peak of the pandemic, including the sequestration of key employees responsible for the overseeing the reliability of system operations, and the purchase of additional personal protective equipment ("PPE") and cleaning services and supplies. During the third and fourth quarters, the impacts of the on-going incremental operating expenses associated with PPE and cleaning were offset by cost reductions as a result of the pandemic, including reduced overtime labor and contractor expense, as well as employee training and travel costs. Increases in the allowance for uncollectible accounts were also recorded in 2020 based on a quantitative and qualitative assessment of future uncollectible expense based on the increase in customer receivable balances in arrears, an historical analysis of the relationship of write-offs to accounts receivable balances in arrears and taking into consideration both current and a forecast of future economic conditions.

Energy supply costs reflect overall lower electric and natural gas commodity prices coupled with lower purchased volumes due to milder weather in 2020 as compared to 2019. This did not have a direct impact on earnings due to the full deferral of commodity costs and the RDM. However, 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. Both the quarter-over-quarter and year-over-year variations in revenues billed through these volumetric factors were not material.

Electricity Sales

Electricity sales were essentially flat compared to 2019, with the increase in residential sales slightly outweighing the decrease in sales to commercial and industrial customers as a result of changes in consumption patterns due to government mandates as a result of the on-going COVID-19 pandemic.

Natural Gas Sales

Natural gas sales increased slightly, with higher sales to interruptible customers, mostly offset by lower sales to firm customers primarily attributed to a warmer than normal 2019-2020 heating season.

Depreciation and Amortization: Depreciation increased due to the increased investment in Central Hudson's electric and gas infrastructure 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, which resulted from the end of the 10-year amortization period of actuarial losses on investments incurred in 2009.

Income Taxes: The combined effective tax rate is lower than the statutory rate due to tax normalization rules and the timing of flow through tax items related to capital expenditures.

Central Hudson Revenues - Electric

Period Ended December 31

(In millions)

	Year to Date		
	2020	**2019**	**Change**
Revenues with Matching Expense Offsets:[(1)]			
Recovery of commodity purchases	$ 129.3	$ 133.9	$ (4.6)
Sales to others for resale	6.8	8.2	(1.4)
Other revenues with matching offsets	69.6	62.3	7.3
Subtotal	205.7	204.4	1.3
Revenues Impacting Earnings:			
Customer sales	358.1	326.8	31.3
RDM and other regulatory mechanisms	(19.8)	(12.7)	(7.1)
Finance Charges	0.8	3.3 [(2)]	(2.5)
Incentives earned	3.3	2.5	0.8
Net plant & depreciation targets	(2.8)	(2.5)	(0.3)
Other revenues	6.8	7.7 [(2)]	(0.9)
Subtotal	346.4	325.1	21.3
Total Electric Revenues	$ 552.1	$ 529.5	$ 22.6

(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.

(2) Other revenues reported for the year ended December 31, 2019 have been reclassified to conform with current period presentation.

Central Hudson Revenues - Natural Gas

Period Ended December 31

(In millions)	Year to Date		
	2020	**2019**	**Change**
Revenues with Matching Expense Offsets:(1)			
Recovery of commodity purchases	$ 29.4	$ 41.4	$ (12.0)
Sales to others for resale	7.9	8.1	(0.2)
Other revenues with matching offsets	7.2	7.5	(0.3)
Subtotal	44.5	57.0	(12.5)
Revenues Impacting Earnings:			
Customer sales	102.7	98.9	3.8
RDM and other regulatory mechanisms	5.7	0.6	5.1
Finance Charges	0.3	1.0 (2)	(0.7)
Incentives earned	1.4	0.8	0.6
Net plant & depreciation targets	(1.4)	(1.2)	(0.2)
Other revenues	6.7	5.1 (2)	1.6
Subtotal	115.4	105.2	10.2
Total Natural Gas Revenues	$ 159.9	$ 162.2	$ (2.3)

(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.

(2) Other revenues reported for the year ended December 31, 2019 have been reclassified to conform with current period presentation.

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, 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 the increase in customer delivery rates as prescribed in the 2018 Rate Order. Although the delivery rate increase approved for July 1, 2020 was delayed until October 1,2020, the associated revenue was recorded as an alternative revenue program and is currently being billed to and recovered from customers over the remaining period of the rate year ending June 30, 2021. Additionally, the Company recorded earnings adjustment mechanisms and earned incentives ("PRA's") in the current year based on achieving certain targets and milestones associated with energy efficiency and customer service as provided in the 2018 Rate Order. Partially offsetting these increases was the discontinuation of finance charges applied on customers' past due balances in order to alleviate additional financial hardship on customers during the current economic conditions as a result of the COVID-19 pandemic. The revenue deferral for the Net plant and depreciation targets resulted from delays in the completion of certain capital projects as compared to levels included in current rates and was offset, in part, by lower depreciation expense compared to the level provided in current rates and higher allowances for funds used during construction. Revenues also reflect lower revenues billed for the recovery of electric commodity costs due to a decrease in electric prices and sales volumes compared to the prior year.

Natural Gas Revenues:

Natural gas revenues decreased year over year as a result of lower natural gas commodity costs driven by decreases in price and sales volume, as well as the discontinuation of finance charges applied on customers' past due balances in order to alleviate additional financial hardship during the current economic conditions caused by the COVID-19 pandemic. These decreases were partially offset by the increase in customer delivery rates effective July 1, 2019 and July 1, 2020. The Company also recorded PRA's in the current year based on achieving certain targets and milestones associated with energy efficiency, reliability and customer service as provided in the 2018 Rate Order.

Central Hudson Operating Expenses

Period Ended December 31

(In millions)	Year to Date		
	2020	**2019**	**Change**
Expenses Currently Matched to Revenues:[1]			
Purchased electricity	$ 136.1	$ 142.1	$ (6.0)
Purchased natural gas	37.6	49.7	(12.1)
Pension & OPEB	13.5	6.0	7.5
New York States energy efficiency programs	39.8	37.9	1.9
Major storm reserve	11.7	6.8	4.9
Low income programs	11.6	9.8	1.8
Other matched expenses	17.7	16.0	1.7
Subtotal	268.0	268.3	(0.3)
Other Operating Expense Variations:			
COVID-19 incremental operating expenses	4.0	-	4.0
COVID-19 related uncollectible reserve	4.9	-	4.9
Depreciation and amortization	66.9	59.4	7.5
Property and school taxes[2]	57.7	53.6	4.1
Weather related service restoration	7.2	5.4	1.8
Distribution and transmission maintenance	6.1	5.4	0.7
Information technology	9.6	8.8	0.8
Labor and related benefits	92.9	91.5	1.4
Tree trimming	22.9	23.1	(0.2)
Other expenses	74.7	74.9 [3]	(0.2)
Subtotal	346.9	322.1	24.8
Total Operating Expenses	$ 614.9	$ 590.4	$ 24.5

(1) Includes expenses that, in accordance with the 2018 Rate Order, 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 Rate Order, 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 $0.5 million, pre-tax per Rate Year.
(3) Certain expenses reported for the year ended December 31, 2019 have been reclassified to "Other" to conform to the current period presentation.

Operating Expenses:

The increase in operating expenses is primarily attributed to increases in certain expenses as provided for in delivery rates including depreciation, property and school taxes and labor and related benefits. In addition, weather related restoration costs increased as a result of several major storm events during the year.

Central Hudson incurred incremental costs in 2020 associated with the COVID-19 pandemic. Specifically, incremental operating expenses included costs for the sequestration of key employees to ensure the continued reliability of system operations during the second quarter of 2020, additional PPE, and cleaning services and supplies. In the second half of the year, the impacts of the on-going incremental operating expenses associated with PPE and cleaning were offset by cost reductions as a result of the pandemic, including labor and contractor expense, as well as employee training and travel costs. Additionally, increases in the allowance for credit losses were recorded in 2020 based on a quantitative and qualitative assessment of future uncollectible expense based on the increase in customer receivable balances in arrears, a historical analysis of the relationship of write-offs to arrears, taking into consideration both, current and estimated forecast of future economic conditions.

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
as of December 31, 2020
(In millions)

Balance Sheet Account	Increase (Decrease)	Explanation
Accounts receivable, net of allowance for credit losses	8.0	Increase is primarily due to the impacts of the COVID-19 pandemic on customers, including legislative actions related to ceasing service terminations for non-payment and offering more flexible payment arrangements.
Other Receivables	(7.6)	Decrease is primarily due to the collection of costs previously billed for contributions in aid of construction to developers for their share of a capital project and for mutual aid related to hurricane restoration efforts in Puerto Rico.
Special deposits and prepayments	5.4	Increase primarily due to the transfer of natural gas balances from Fuel, Material and Supplies as a result of the Asset Management Agreement, coupled with the prepayment of school taxes.
Regulatory assets / liabilities - related to pension plan costs	9.3	Increase in regulatory asset (coupled with the decrease in the prior year regulatory liability balance) primarily attributed to the decrease in the funded status of the plans as described below within the change to Accrued Pension costs.
Regulatory assets - long term	39.4	Increase primarily reflects an increase in amounts accrued for future environmental remediation costs at the North Water Street manufactured gas plant ("MGP") site coupled with several major storm events in 2020, higher deferred taxes recoverable through future rates attributable to plant and the deferral of Rate Year 3 electric rate increases.
Prefunded OPEB costs	(6.0)	Decrease is the result of an increase in the projected benefit obligation due to a decrease in discount rate and unfavorable claims experience, which was only partially offset by investment gains on the OPEB plan assets.

Other investments	7.7	Increase primarily due to funding of the non-qualified Supplemental Executive Retirement Plan.
Long term debt, including current maturities	90.0	Increase is due to the issuance of $130 million in long-term debt during 2020, partially offset by the repayment of $40 million of maturing debt in September 2020.
Notes Payable	15.0	Increase is related to short-term borrowings to meet working capital needs.
Accounts payable	8.5	Increase is primarily due to costs associated with major storm restoration efforts, environmental remediation costs at the North Water Street MGP site and payments to New York State Energy Research and Development Authority ("NYSERDA") for Clean Energy Fund ("CEF") initiatives.
Regulatory liabilities - current	(5.7)	Decrease is primarily due to payments submitted to NYSERDA to fund CEF initiatives in excess of amounts collected, bill credits provided to customers per the 2018 Rate Order, partially offset by amounts billed to customers in excess of revenue targets.
Accrued environmental remediation costs, net	17.9	Net increase is primarily due to higher estimated remediation costs related to the North Water Street MGP site as a result of a change in the expected method of remediation.
Regulatory liabilities - long term	(11.9)	Decrease is primarily due to bill credits provided to customers per the 2018 Rate Order, the amortization of plant related deferred tax liabilities as a result of the Tax Cuts and Jobs Act and an increase in energy efficiency program expenses above amounts included in rates. Partially offsetting these decreases were negative revenue adjustments ("NRAs") related to net plant and depreciation targets.
Regulatory liabilities - related to OPEB costs	(13.1)	Decrease is primarily attributed to the decrease in funded status of the plan as described above within the change to Prefunded OPEB costs.
Accrued pension costs	14.1	Increase is primarily due to an increase in the projected benefit obligation due to a decrease in the discount rate and assumption changes resulting from the updated experience study, which were only partially offset by investment gains on retirement income plan assets and an update to the mortality projection scale.
Other liabilities - long term	5.6	Increase is primarily due to a deferral of payment of payroll taxes in accordance with the Coronavirus Aid, Relief, and Economic Security ("CARES") Act.

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	
	2020	**2019**
Cash, cash equivalents and restricted cash - beginning of period	$ 21.1	$ 43.8
Cash from operations pre-working capital	142.4	126.9
Working capital	(11.4)	4.5
Operating Activities	131.0	131.4
Investing Activities	(256.8)	(237.8)
Financing Activities	117.5	83.7
Cash, cash equivalents and restricted cash - end of period	$ 12.8	$ 21.1
Dividends paid on Common Stock - CH Energy Group	$ -	$ (16.5)

Operating Activities: The increase in cash from operations pre-working capital in 2020 as compared to 2019 was primarily attributable to the growth in net income from delivery rate increases which provided earnings on rate base and the recovery of eligible deferrals through the rate adjustment mechanisms. These were partially offset by higher expenditures for major storm restoration. Working capital needs resulted in a draw on cash flow in 2020 primarily due to the impacts of the COVID-19 pandemic, most notably the impacts on customer billings and collections. Additionally, there was an increase in remittances of CEF collections to NYSERDA in 2020 and increased funding for certain internal energy efficiency programs to provide customers assistance in reducing their energy consumption and costs during the pandemic. The impact of these items on working capital was partially tempered by lower commodity costs, delayed payment of payroll taxes in accordance with the CARES Act and lower income taxes paid due to the utilization of net operating losses in 2020.

Investing Activities: Cash used in investing activities during 2020 increased $19 million, as compared to 2019 due to increased investment in Central Hudson's utility plant. The long-term capital program provides for continued strengthening of existing electrical and natural gas infrastructure, resiliency and automation of distribution systems, new common facilities and investments in information and distribution system technologies.

Financing Activities: During 2020, Central Hudson issued $130 million in Senior Notes, as compared to $100 million in the prior year. Proceeds received were used for general corporate purposes, including the repayment of a higher level of maturing debt and capital investments. The Company did not pay dividends in 2020 compared with the payment of $16.5 million in common stock dividends in 2019.

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, the subsidiary 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 capital 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 of approximately 50%, excluding short-term debt balances. Central Hudson plans to utilize short-term debt to fund seasonal and temporary variations in working capital requirements. If wholesale energy prices increase, Central Hudson would expect a corresponding increase in its current level of working capital.

Central Hudson's secondary sources of funds is its cash reserves and credit facilities. Central Hudson's ability to use its credit facilities is contingent upon maintaining compliance with certain financial covenants. Central Hudson does not anticipate that those covenants will restrict its access to funds in 2021 or the foreseeable future.

CH Energy Group and Central Hudson are actively monitoring effects on cash flow related to the impact of COVID-19 on the economy of its utility service territory, customers, and operations. As a provider of essential electricity and natural gas services, Central Hudson continues to see uninterrupted demand. Cash expended by the Company in pandemic response activities is expected to be partially mitigated by reductions in other planned expenditures. Central Hudson has not experienced any issues with accessing capital markets during the pandemic, having successfully secured new financing in the third quarter at favorable interest rates. Central Hudson has also filed a request for a delivery rate increase to be effective July 1, 2021. While Management took initiatives to mitigate the impact of the rate increase on customers during this difficult economic environment, the requested increase would continue to provide the necessary cost recovery to ensure safe and reliable service, as well as a reasonable rate of return on its investments. At this time, CH Energy Group believes cash generated from operations and funds obtained from its financing program will be sufficient in 2021 and the foreseeable future to meet working capital needs, pay dividends on its Common Stock, fund Central Hudson's capital program and CHET's 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 September 13, 2018, authorizing Central Hudson to enter into new credit agreements with maturities of no more than five years and in an aggregate amount not to exceed $200 million. On March 13, 2020, Central Hudson entered into a $200 million, five-year revolving credit agreement with five commercial banks to replace the agreement that was set to expire on October 15, 2020. Proceeds received from the new revolving credit agreement are to be 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 or Moody's rating on the average daily unused portion of the credit facility.

On July 10, 2015, CH Energy Group entered into a Third Amended and Restated Credit Agreement with four commercial banks. The credit commitment of the banks under the facility was $50 million with a maturity date of July 10, 2020. Due to low demand for cash and the ability to receive funding from either dividends or equity capital contributions, CH Energy Group did not replace this credit agreement upon its maturity.

On a consolidated basis, CH Energy Group's committed credit as of December 31, 2020 and December 31, 2019 was $200 million and $250 million, respectively. There were no borrowings outstanding under the various credit arrangements as of December 31, 2020 and 2019.

Uncommitted Credit

At December 31, 2020, Central Hudson had uncommitted short-term credit arrangements with two commercial banks totaling $30 million. At December 31, 2019, Central Hudson had uncommitted short-term credit arrangements with three commercial banks totaling $40 million.

At December 31, 2020, CH Energy Group and Central Hudson had $15 million in borrowings outstanding under Central Hudson's uncommitted credit agreements with an effective weighted average interest rate of 0.9%. There were no outstanding borrowings under the uncommitted credit agreements at December 31, 2019.

Central Hudson's Bond Ratings

	December 31, 2020		December 31, 2019	
	Rating(1)	Outlook	Rating(1)	Outlook
S&P	A-	Stable	A-	Stable
Moody's	A3	Negative	A3	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 October 13, 2020, Moody's affirmed the rating of Central Hudson's senior unsecured debt and changed its rating outlook from stable to negative. Moody's indicated that the outlook reflects its view that the growing capital expenditure program, compounding the on-going impacts of federal tax reform on operating cash flow generation, could continue to have a negative impact on the Company's financial ratios. In addition, Moody's cited an increasingly challenging regulatory environment in New York State that could have an impact on the outcome of the Company's pending rate case. On December 11, 2020 Fitch affirmed its rating (A-) and 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 securities with maturities greater than 12 months.

In accordance with the approved 2018 Financing Order, Central Hudson is authorized to issue and sell long-term debt in an aggregate amount not to exceed $425 million through December 2021, including $360 million for traditional utility purposes and up to $65 million to refinance its variable interest debt.

On November 17, 2020, Central Hudson issued $30 million of Series T Senior Notes, with an interest rate of 2.03% per annum and a maturity date of November 17, 2030. On September 28, 2020, Central Hudson issued $40 million of Series S Senior Notes, with an interest rate of 2.03% per annum and a maturity date of September 28, 2030. On July 14, 2020, Central Hudson issued $30 million of Series R Senior Notes, with an interest rate of 3.62% per annum and a maturity date of July 14, 2060. On May 14, 2020, Central Hudson issued $30 million of Series Q Senior Notes, with an interest rate of 3.42% per annum and a maturity date of May 14, 2050. Central Hudson used the proceeds from the sale of the Senior Notes to repay $40 million of maturing debt and for general corporate purposes, including the funding of capital expansion and improvement projects and the repayment of short-term borrowings.

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 viable.

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

CH Energy Group

	December 31, 2020		December 31, 2019	
		%		%
Long-term Debt[1]	$ 847.5	49.3	$ 759.2	49.6
Short-term Debt	15.0	0.9	-	-
Common Equity	855.8	49.8	772.6	50.4
Total	$ 1,718.3	100.0	$ 1,531.8	100.0

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

Central Hudson

	December 31, 2020		December 31, 2019	
		%		%
Long-term Debt[1]	$ 837.0	49.1	$ 747.0	49.2
Short-term Debt	15.0	0.9	-	-
Common Equity	852.4	50.0	772.2	50.8
Total	$ 1,704.4	100.0	$ 1,519.2	100.0

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

In accordance with the 2018 Rate Order, Central Hudson's customer rates were premised on a capital structure, excluding short-term debt with a common equity ratio of 49% for the rate year beginning July 1, 2019. Beginning July 1, 2020 the common equity ratio increased to 50%. Central Hudson continues to manage its financing to maintain its common equity ratio at approximately 50%.

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 2018 Rate Order, including a return on equity of 8.8%.

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 experience and on various other assumptions that we believe 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 a number of underlying variables, many of which are beyond our control. Actual results may differ from these estimates under different assumptions or conditions.

We believe the following judgments and estimates are critical in the preparation of Central Hudson’s 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 expense or revenue 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, the regulatory agencies can provide flexibility in the manner and timing of recovery of regulatory assets.
- Depreciation and amortization is 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 service 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 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 associated with gas code rule compliance audits.

Changes in Internal Controls over Financial Reporting

There have been no material changes in CH Energy Group's or Central Hudson's internal control over financial reporting during the year ended December 31, 2020.

Regulatory Proceedings

<u>2018 Rate Order</u>
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 adopted the terms set forth in the April 18, 2018 Joint Proposal, with minor modifications. The 2018 Rate Order was effective July 1, 2018, with Rate Year 1, Rate Year 2 and Rate Year 3 defined as the twelve months ending June 30, 2019, June 30, 2020 and June 30, 2021, respectively.

The 2018 Rate Order provides electric delivery revenue increases of $19.725 million, $18.581 million and $25.083 million in Rate Year 1, Rate Year 2 and Rate Year 3, respectively and gas delivery revenue increases of $6.654 million, $6.702 million and $8.183 million Rate Year 1, Rate Year 2 and Rate Year 3, respectively. The Rate Order also provides electric bill credits of $6.0 million in Rate Year 1, $9.0 million in Rate Year 2, and $11.0 million in Rate Year 3; and gas bill credits up to $3.5 million in Rate Year 1 and $4.0 million in Rate Years 2 and 3.

On June 11, 2020, the Commission issued Order Postponing Approved Electric and Natural 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 Rate Year 3 electric and natural gas delivery rate increase scheduled to take effect on July 1 to October 1, 2020, without carrying charges and provided recovery of the forgone revenues over the period from October 1, 2020 through June 30, 2021. Central Hudson's RDM Targets were adjusted to be consistent with the delayed electric and natural gas delivery rate increase implementation.

On June 18, 2020, Central Hudson filed its Assessment of Natural Gas Demand Side Load Management Programs with the Commission in compliance with the 2018 Rate Order and Case 18-M-0084 based on the required Request for Proposal ("RFP"). The RFP, which currently is underway, was designed to solicit technology and fuel neutral market responses to a defined level of peak reduction. Central Hudson will conduct an analysis including a benefit cost analysis ("BCA")to determine the potential value of various levels of peak reduction provided by a Demand Response program. Following the implementation of a Gas Demand response program, annual reports that include an updated BCA will be filed with the Secretary within 60 days of the end of each Rate Year.

August 2020 Rate Filing

Central Hudson filed an electric and natural gas rate case (Cases 20-E-0428 and 20-G-0429) on August 27, 2020 with the PSC seeking electric and natural gas delivery revenue increases of $32.8 million and $14.4 million, respectively, to become effective July 1, 2021. The filing includes net regulatory liability balances proposed for rate moderation of $20 million for electric and $8 million for natural gas. The rate filing was made in order to align electric and natural gas delivery rates with the projected costs of providing service to our customers and reflects a return on equity of 9.1% and a 50.0% equity ratio to maintain financial integrity. Additionally, due to the severe economic impact of COVID-19 within its service territory, Central Hudson included specific actions within the filing to reduce the customer bill impact, which included delaying a meaningful portion of the capital plan ($48.5 million during the rate year ending June 30, 2022) and a COVID-19 Adjustment Customer Bill Moderation credit that reduces Central Hudson's revenue requirements by $1.8 million for electric and $0.5 million for natural gas.

The primary drivers for the increase in projected costs include: 1) capital investments to modernize Central Hudson's electric and natural gas infrastructure and information technology) systems resulting in increases in depreciation expense, return on rate base, and property taxes; 2) increasing expenses associated with vegetation management or trimming; 3) increasing employee levels and labor costs; and 4) initiation of a new Heat Pump program. Modernization of electric transmission and distribution infrastructure addresses the underlying age and condition of the assets and the need to enable the Distributed System Platform in order to better monitor and control the distribution system while facilitating increasing levels of Distributed Energy Resources penetration. This is directly tied to the goals of CLCPA. Central Hudson's filing also proposes the continued replacement of gas Leak Prone Pipe ("LPP"), replacing 15 miles per year resulting in an elimination of LPP from the Company's natural gas system in approximately eight years. Central Hudson also proposes to invest in information technology systems to transform and modernize customer interactions, complete the replacement of its 40-year old Enterprise Resource Planning mainframe solution and sustain the security and maintenance of its IT systems. Central Hudson is also proposing additional funding to maintain a four-year cycle for distribution line clearance and a five-year cycle for its transmission right-of way trimming maintenance while implementing a targeted tree removal program aimed at reducing the impact of the increasing number of severe weather events brought about by climate change and the proliferation of invasive insect infestations and tree diseases. Central Hudson is also seeking recovery of costs associated with the New York State Clean Heat program, which seeks to replace high carbon intensive heating sources with heat pumps and related measures.

The filing also proposes to:

1) modify and expand the current Earnings Adjustment Mechanisms ("EAM") that were approved in the 2018 Rate Plan;
2) introduce new PRAs while eliminating or modifying the structure of certain NRAs;
3) expansion of Central Hudson's RDMs to include additional service classes;
4) institute new deferral mechanisms, including authority to defer incremental COVID-19 related costs and lost revenues; and
5) expand the eligibility criteria for the Low Income Bill Discount Program to include customers who receive other forms of public assistance.

PSC Staff and intervenor testimony was filed on December 22, 2020. Central Hudson and certain intervener's filed rebuttal testimony on January 22, 2021. A PSC Order in response to the filing is anticipated with new rates to become effective July 1, 2021.

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. On August 19, 2020, the Office of Investigations and Enforcement of the DPS issued a Notice of Apparent Violations Related to Tropical Storm Isaias (the "Notice") to the Company. The Notice identified two potential violations based on the Staff's initial investigation into Central Hudson's storm response to Tropical Storm Isaias. On November 19, 2020, DPS Staff 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 ("ERPs"). On the same day, the Commission issued an Order to Commence Proceeding and Show Cause ("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 result in up to $16 million of penalties. The Show Cause Order directed the utilities to respond to the allegations of noncompliance within 30 days and to show cause why civil penalties or appropriate injunctive relief should not be imposed to remedy such noncompliance. 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, believes no penalty should be issued because the facts demonstrate that Central Hudson fully complied with its PSC approved ERP, which serves as the standard against which Central Hudson should be evaluated. As such, no accrual has been made related to this Proceeding and Show Cause Order or the Notice. On January 20, 2021, the PSC authorized the appointment of Administrative Law Judges to the pending proceedings and authorized the holding of evidentiary hearings. Management cannot predict the outcome of this matter or the impact it may have on Central Hudson's earnings, financial position or cash flows.

Central Hudson Reverse Sales Tax Refund

On March 16, 2020, Central Hudson filed a petition for the disposition of a sales tax refund, pursuant to PSL Section 113(2) under Case 20-M-0134. The tax refund is the result of a reverse sales tax audit that Central Hudson initiated with the New York State Department of Taxation & Finance for the claim period of June 1, 2017 through December 31, 2018. The Commission solicited comments on the filing via notice published in the April 22, 2020 edition of the New York State Register. Central Hudson asked the Commission to take notice of a tax refund received from the New York State Department of Taxation and Finance, in the amount of approximately $3.4 million on October 16, 2019 and waive the rule requiring the Company to give the Commission notice of the refund within 60 days. Central Hudson proposed that the refund received be allocated (1) for the benefit of ratepayers; and (2) to reimburse the costs incurred by Central Hudson in securing the refund. The Company proposed to retain approximately $0.6 million, or 24% of the refund, net of costs to achieve. Most of the refund has been credited to plant as the majority of the refund related to sales taxes that were capitalized as part of plant costs. The petition requested the PSC approve Central Hudson retaining the portion of the net refund related to amounts that were previously recorded to sales tax expense.

On June 18, 2020, Multiple Intervenors ("MI") filed comments in response to Central Hudson's petition that recommends the Commission direct Central Hudson to distribute customers' share of the tax refund directly to customers in the form of bill credits as expeditiously as practicable to provide immediate financial assistance to customers when it is most needed and proposed the refund should be returned to customers utilizing the same allocation methodology as was employed by Central Hudson to collect the taxes in the first place. Staff's testimony in the August 2020 filing requested that this proceeding be incorporated into the Rate Case filing rather than ruled upon separately. Although the outcome is unknown, any potential adjustments that may result from a PSC ruling differing from how the refund has been recorded to date is not expected to be material to Central Hudson's financial statements.

Central Hudson 2018 Financing Order
On September 13, 2018, the Commission approved the Company's request under Section 69 of the Public Service Law to enter into multi-year committed credit agreements in an aggregate amount not to exceed $200 million and maturities not to exceed five years, to issue and sell long-term debt in an aggregate amount not to exceed $425 million through December 2021, and to enter into derivative instruments to hedge interest rate risk for its variable rate debt obligations.

FERC 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 System Deliverability Upgrades ("SDU") 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. FERC has appointed a settlement judge and Central Hudson has circulated a settlement proposal at an updated Return on Equity ("ROE") of 9.4% plus a 50 basis point technology adder for a total ROE of 9.9%. Settlement conferences are in process.

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.

Value of Distributed Energy Resources Proceeding ("DER") – 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. These compensation reforms are being considered as a reform to net metering. The Joint Utilities ("JU") believe that a demand-based rate structure will more accurately reflect utility cost causation, deliver efficient price signals and lead to distributed energy resource investment decisions that appropriately reflect grid impacts and support REV goals.

On April 18, 2019, the PSC issued an Order Regarding Value Stack Compensation, which is intended to improve the predictability, transparency, and accuracy of Demand Reduction Value ("DRV"), Locational System Relief Value ("LSRV"), and Capacity Value calculations and compensation as well as an authorized new rate component to encourage robust Community Distributed Generation ("CDG") development. In addition, the Order provided for an opt-in to participate in Central Hudson's demand response programs as an alternative to DRV and LSRV compensation, the expansion of Phase One Net Energy Metering eligibility for certain demand-billed customer projects under 750 kilowatts and a provision for a Community Adder as an upfront incentive for Market Transition Charge replacement applicable to the development of at least 50 MW of new CDG projects funded by NYSERDA from previously collected, uncommitted ratepayer funds.

On December 12, 2019, the Commission issued an Order Regarding Modifications to Value Stack Compensation for High-Capacity-Factor resources. The order directed utilities to adjust the Market Transition Credit and Community Credit that is applicable to subscribers of qualifying CDG projects with generation produced by dispatchable, high-capacity-factor resources, specifically fuel cells and also to limit the Environmental component of the Value Stack to renewable energy systems with resources that are defined under PSL 66 (p). These changes were made to the Company's tariffs to be effective February 1, 2020.

On May 16, 2019, the PSC issued an Order on Standby and Buyback Service Rate Design and Establishing Demand Based Rates. The Order provides current Standby and Buyback customers an increased ability to manage their usage and provides other customers the benefits of standby service rates as optional rates. Effective July 1, 2019, the tariffs offer Standby Service Rates to all demand-metered customers, in lieu of customer's existing rate structure. Customer's opting-in to standby rates must do so for a period of not less than one year and will continue to be included in the RDM reconciliation. A reliability credit, which provides a monetary credit based on the difference between a customer's Contract Demand and maximum Daily As-Used Demand, will be restricted by excluding customers' DERs that receive Value Stack compensation for exports to the system. A 5 MW project-level uninstalled capacity compensation limit was established for installed capacity purchased from buyback service customers, consistent with the maximum project size allowed under VDER. Resources with a capacity greater than 5 MW operating under existing capacity purchase contracts will be grandfathered.

On June 12, 2020, the Commission issued Order Granting Reconsideration Regarding Compensation of Community Generation Compensation in response to a petition filed April 19, 2020 by the Coalition for Community Solar Access and New York Solar Energy Industries Association. The Order directs that the Proposed Community Credit ("CC") in the VDER Compensation Order will be part of the compensation for large customers of each eligible CDG project starting with the first billing cycle for that project for which the entire billing period falls after July 31, 2020. The CC authorized in this Order will not be provided for generation for which CDG members have already received compensation.

On July 16, 2020, the Commission issued Order Establishing Net Metering Successor Tariff setting forth directives that allow certain Distributed Generation projects utilizing Net Energy Metering-eligible technologies, to be eligible for a range of delivery rate options presently offered in utility tariffs, including standard, time-of-use and standby rates, while beginning to address cost shifts and improve incentives. The Order also establishes a Customer Benefit Contribution which is a monthly $/kW charge to recover public benefit program costs applicable to customers that install solar photovoltaic technology and interconnect on or after January 1, 2022.

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 recommends a standardized ACOS study methodology and rate design for standby rates and buyback service rates for stand-alone energy storage systems. The whitepaper recommends that each of the Joint Utilities file new ACOS studies and resulting rates based on a consistent standardized methodology. The whitepaper also recommends that the Commission implement an exemption from Buyback Service Contract Demand Charges for stand-alone energy storage systems that export electricity to the electric grid. Initial Comments are due February 15, 2021 and Reply Comments are due March 1, 2021.

<u>Hybrid Storage Energy Systems</u>

On December 13, 2018 the Commission issued an Order Implementing a Hybrid Energy Storage System Tariff. Owners of Hybrid Facilities must choose one of four metering options prior to operation and owners are responsible for paying for necessary metering and/or controls consistent with the Standard Interconnection Requirements. The four metering options are: 1) designed for a project where the owner intends to charge the hybrid facility exclusively from a renewable generator and not from the utility system, 2) designed for projects where the owner intends to use the storage resource only to serve on-site load and not to inject energy into the utility system, 3) designed for projects where the storage resources may be charged from both a renewable generator and the utility site and both the renewable generator and the storage system may be used to inject into the utility system for compensation and 4) applies to Hybrid Facilities that are separately sited. Owners may make a one-time, irrevocable decision to switch from Option 1 or 2 to Option 3. The hybrid energy storage system tariffs became effective January 1, 2019.

Climate Change Risk Reporting
On October 15, 2020, the Commission issued Case 20-M-0499, an Order Instituting Proceeding to consider adoption of the Financial Stability Board's Task Force on Climate-related Financial Disclosure recommendations for a uniform approach and set of corporate-related financial disclosures at the utility operating company level. The Commission's Order states that for public utilities with significant assets and changing physical infrastructure needs, increased transparency of climate related financial risks would allow for better planning and investment consistent with New York State's climate goal of a carbon neutral economy by 2050. The Order seeks to gather information from utility operating companies and other interested parties, including pros/cons and costs/benefits of climate risk disclosure and the use of a uniform framework. On December 15, 2020, the JU filed comments in response to the Commission's October Order supporting the use of enhanced climate risk reporting at the operating company level based on the AGA/EEI Template and recommended that this information be provided through separate annual filings with the Commission in a new proceeding.

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. As directed in the Order, Staff filed two whitepapers which establish a Data Access Policy Framework that standardizes necessary privacy, cyber security and quality requirements for access to energy related data and the creation of an integrated energy data resource that provides a platform for access to customer and system data. The Staff Whitepaper Regarding Data Access Framework creates a statewide certification process to grant Energy Service Entity ("ESE") access to energy-related customer data. Staff recommends the Commission direct individual utilities to submit a compliance filing that details how each utility has updated all existing policies to comply with the Data Access Framework. The whitepaper also recommends the Commission direct the JU to file for Commission review and approval an implementation plan for ESE risk management program and implementation plan for an interim centralized certification model. The purpose of the Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource ("IEDR") is to provide useful access to energy data and enable achievement of CLCPA. Staff recommends the Commission adopt a statewide NYSERDA sponsored IEDR, funding framework and governance, for which the utility would have a small role. Technical Conferences for Data Access and Data Framework were held July 21 and 22, 2020, respectively. The JU filed initial comments on August 24, 2020 and reply comments on September 11, 2020. In October, Staff issued a series of interrogatories to each utility requesting cost estimates for an IEDR implementation. The JU worked with Staff collaboratively in preparation of their information request responses which were filed with Staff on December 11, 2020.

Gas Planning Procedure
The Commission issued an Order Instituting Proceeding on Gas Planning on March 19, 2020 in Case 20-G-0131. This proceeding was initiated to ensure more useful and comprehensive planning for natural gas usage and investments in New York State. The proceeding will focus on several major issues including examining constraints, gas planning, non-pipe solutions, gas moratoria standards and demand-side resources.

Central Hudson and the Joint Local Distribution Companies ("LDCs") filed the following items in compliance with the Order:

- Supply/demand analysis for locations identified as "vulnerable" within each utility service territory on July 17, 2020 (as amended);
- Supply/demand analysis for the entire utility service territory on July 31, 2020 (as amended);
- Peaking Services and Moratorium Management Proposal on July 17, 2020;
- Utility Status Report/Proposals on Plans for Utilizing Demand Reducing Measures (Energy Efficiency ("EE"), Demand Reduction Non-Pipe Alternatives, other) to aid in management of moratoria (including existing EE and electrification programs and targets) on August 17, 2020; and
- Staff Proposal to Modernize Gas System Planning Process was extended to February 12, 2021.

COVID-19 Related Orders and Proceedings

On March 7, 2020, New York State Governor Andrew Cuomo issued Executive Order 202 Declaring a Disaster Emergency in the State of New York which addresses the threat that COVID-19 poses to the health and welfare of New York's residents and visitors. The Executive Order has been extended several times and is currently in effect until January 29, 2021. Central Hudson has suspended terminations or shut-offs for customers and has aided customers impacted by COVID-19 who may be experiencing financial hardship. Effective April 1, 2020, Central Hudson began waiving finance charges for late payments.

On April 6, 2020, the Commission issued an Order Suspending Certain Payment Obligations related to Standardized Interconnection Requirements. These payments relate to the final 75% of estimated interconnection costs paid to the utility by applicants and are suspended for the length of the Disaster Emergency plus thirty calendar days. This Order also directed electric utilities to continue all interconnection activities that can be conducted in accordance with the Governor's orders relating to the conduct of essential and non-essential work.

On April 15, 2020, the Commission issued an Order Granting Extension of Time to Complete Gas Service Line Inspections and Leakage Surveys. These extensions were necessary to protect the health and safety of LDCs' employees, customers, and the general public during the COVID-19 pandemic because completing these inspections would require LDC employees to enter buildings for non-emergency reasons, which would risk community contact transmission of the COVID-19 virus. On September 2, 2020, the National Gas Association, on behalf of the New York State LDCs, submitted a report with a progress summary and proposed next steps to complete the Gas Service Line Inspection and Leakage Surveys with Staff and proposed to work collaboratively with Staff to further advance completion of baseline inspections hindered by access issues.

On April 10, 2020, MI filed a petition with the Commission requesting an expeditious ruling and recommendation that, at a minimum, surcharges and collections devoted towards funding programs and projects be either reduced or delayed providing relief to customers. The petition also proposed that prior collections from customers for such programs and projects that remain uncommitted be returned to customers and to the extent activity in such programs and projects has been paused due to the pandemic, current customer collections to fund such programs similarly should be paused. MI filed supplemental comments to support its April 10, 2020 petition that cited NYSERDA's "Clean Energy Fund Quarterly Performance Report through December 31, 2019" (dated March 2020) that indicates (1) As of December 31, 2019 $1.2 billion of the amount approved for collection across all New York State utilities remained unspent and uncommitted and could be utilized to provide much-needed rate relief to customers during these very-challenging times and (2) Central Hudson has a regulatory liability of approximately $59.3 million as of June 30, 2020 associated with CEF collections from customers in excess of amounts drawn by NYSERDA for program spending. The Commission incorporated this filing into the new proceeding, Case 20-M-0266 further discussed below.

On April 20, 2020, Public Utility Law Project of New York ("PULP") filed a petition with the PSC requesting the Commission to commence a proceeding to investigate and consider the effects of COVID-19 and the impacts of Governor Cuomo's Executive Order 202 on the rates and provisions of utility services. The petition urged that utilities currently in litigation, settlement or with recently filed rates cases be required to file up-to-date rate case quality data, and that these utilities should be required to file potential austerity updates and adjust their requested return on equity and debt to equity ratios. PULP also stated that rate increases included in approved multi-year rate plans currently in effect are based on inaccurate data and will devastate individuals already suffering in the aftermath of the COVID-19 crisis. PULP's petition identified a need for the Commission and the Office of Temporary and Disability Assistance to determine a method that will ensure customers can still receive Emergency

Home Energy Assistance during the moratorium on utility service shutoffs. The Commission incorporated this filing into the new proceeding, Case 20-M-0266 further discussed below.

On June 11, 2020, the Commission 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 Commission 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 Commission's clean energy programs should be maintained or accelerated. Public comments on the following topics: collection and termination of service, commission principles in serving the public interest and rate and financial aspects, as provided in an Appendix to the Order, were filed by parties on July 13, 2020 and reply comments were filed August 28, 2020. As requested by Staff, utilities are providing on a monthly basis, financial information to enable an assessment of the COVID-19 impacts on utility earnings and cash flow. Central Hudson is providing the monthly requested information to Staff with regards to COVID-19 lost finance charge revenues and incremental costs, including the increase in past due balances and the uncollectible reserve and cost reductions.

On June 17, 2020, Governor Cuomo signed legislation (S8113A), which amended Public Service Law 66, Section-32 for a period of time currently set to expire March 31, 2021. The bill prohibits any utility corporation or municipality from terminating or disconnecting services to any residential customer for the non-payment of an overdue charge for the duration of the COVID-19 state disaster emergency declared pursuant to Executive Order 202. Further, the law imposed a duty on utility corporations and municipalities to restore service, to the extent not already required under the law, to any residential customer within forty-eight hours if such service was terminated during the pendency of the COVID-19 State of Emergency.

<u>Offshore Wind Proceeding</u>

On July 12, 2018, the Commission issued an Order Establishing an Offshore Wind ("OSW") Standard and Framework for Phase 1 Procurement under Case 18-E-0071, in order to comply with NYSERDA's New York State Offshore Wind Master Plan, a comprehensive roadmap that encourages the development of at least 2,400 MW of offshore wind capacity to be operational by 2030. NYSERDA will serve as the procurement agent for OSW.

The standard calls for Phase 1 Offshore Renewable Energy Credits ("ORECs") associated with approximately 800 MW of OSW to be procured over a two-year period. On July 18, 2019 Governor Cuomo announced the selection of two offshore wind building projects that include an 880 MW project and 816 MW project. LSEs were obligated to acquire, on behalf of their retail customers, the ORECs procured in Phase 1 in an amount proportional to their load in relation to the energy load served by all LSEs in the New York Control Area.

On April 23, 2020, the Commission issued an Order Authorizing Offshore Wind Solicitation, allowing NYSERDA to issue an additional offshore wind solicitation in 2020 for 1,000 MW or more in response to a petition filed by NYSERDA. The petition is based on NYSERDA's goal of maintaining its trajectory toward meeting its Clean Energy Goals as detailed in the CLCPA, which requires 9,000 MWs of OSW to be operational by 2035. As part of this goal, NYSERDA executed contracts for two proposals with an aggregate nameplate rating of 1,696 MWs at an average OREC price of $25.15 and took advantage of the extension of the federal Investment Tax Credit of 18% which applies to wind facilities that begin construction during 2020. The Order directed NYSERDA to conform its solicitation with the Index REC Order where developers have the option to bid either a Fixed-Price OREC bid or an Index OREC bid, but not both. NYSERDA will use a Reference Energy Price that reflects the average Locational Based Marginal Pricing from a project's zone of delivery and a Reference Capacity Price that is calculated using a project's specific NYISO-designated locality. Developers have the option to select an

Uninstalled Capacity production factor that will be utilized for the life of the contract and a ceiling on the index price payable for all hours was set at the strike price.

Energy Storage System Proceeding

In January 2018, Governor Cuomo announced a target to install 1,500 MW of Energy Storage Systems in New York State by 2025. On June 21, 2018, PSC Staff and NYSERDA released their proposal to achieve this target in their Energy Storage Roadmap. The roadmap groups storage application into three market segments – customer sited, distribution system and bulk system – based on where storage is located on the electric grids and the needs it serves.

On December 13, 2018, the Commission issued its Order Establishing Energy Storage Goal and Deployment Policy. Each electric Investor Owned Utility was required to issue a Request for Proposal in 2019 to competitively procure dispatch rights for bulk-level energy storage systems sited within their service territory. On September 30, 2019, Central Hudson posted its RFP and Energy Storage Service Agreement Terms and Conditions for prospective bidders and stakeholders to prequalified bidders. Central Hudson received proposals for six projects. On July 1, 2020, Central Hudson reviewed those proposals with Staff, which were not economically viable, and none accepted.

On September 17, 2020, the Commission issued an Order Establishing Term –Dynamic Load Management ("DLM") and Auto-Dynamic Load Management Procurements and Associated Cost Recovery to address longer-term rule and price certainty in the DLM programs. The Order implements two new DLM program options (Term-DLM and Auto-DLM) which will provide incentive payment certainty for participants for a period of three years or longer. The Order was established to incentivize customers on the use of energy storage technologies and encourage further deployment of these solutions. The Order directs the following:

- Resources to be operational and provide load relief by May 1, 2021;
- Resources for both programs be procured through a sealed-bid, pay-as-bid auction method;
- Require utilities to develop bid ceiling prices, consulting with Staff that bid ceilings are proper and consistently designed prior to determining the bids to award;
- Payment structure with contract value equally spread over the contract term subject to performance requirements;
- Term-DLM Day Ahead Peak Shaving Program whereby participants will provide load relief on not less than 21 hours advance notice during a specified four-hour period and available throughout the utility service territory (called only Mon-Fri and may participate in DLRP during the same period); and
- Auto-DLM Reliability and Peak Shaving Program whereby participants will provide load relief on not less than 10 minutes advance notice at any time, except for specified off-peak charging hours, for a period of four hours. (This program is available in specified areas of each utility's service territory and customers cannot participate in any other distribution DR program.)

On November 16, 2020, Central Hudson made tariff filings describing cost allocation and cost recovery in compliance with the Order. The Order is temporarily effective December 1, 2020, with the report on the effectiveness of Term DLM and Auto-DLM to be included in the utility's annual DLM report due November 15, 2021. On December 9, 2020, the Company submitted its RFP seeking three-year contracts for resource participation in the DLM Programs.

Electric Vehicle ("EV") Direct Current Fast Charging ("DCFC") Infrastructure Program

On February 7, 2019, the Commission issued an Order Establishing Framework for a DCFC Infrastructure program. The Order adopted the multi-party DCFC per plug incentive proposal to support critical public infrastructure in furtherance of the State Energy Plan carbon reduction targets and zero emission vehicle deployment goals. On January 13, 2020, Staff issued its Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment. A Commission notice and formal comment period is expected to follow.

On March 2, 2020, Central Hudson filed its 2019 Annual Report describing participation in the program, geographic plug location, installation costs, energy usage details and technologies used to manage demand.

On March 19, 2020, the Commission issued Order Providing Clarification and Modifying Direct Current Charging Incentive Program which adopted the following clarifications/modifications to the previous EV DCFC orders, including:

- Tesla's method of payment will qualify under the DCFC incentive program;
- DCFC per-plug incentive program data collection will only be used publicly in fully anonymized aggregated annual reports;
- A two-year extension of the 2019 incentive level to December 31, 2021 was approved;
- DCFC per-plug incentive program rules were modified so that, at co-located stations, any plug type capable of simultaneously charging two vehicles at 75 kW or greater will receive a full per-plug incentive, and standardized plug equipment at the site capable of simultaneously charging two vehicles at 62.5 kW to 74 kW will receive 60% of full incentive;
- Mixed tier incentives will cease after three years on March 19, 2023; and
- No single station developer or operator may seek incentives for installations of greater than 50% of the plugs per utility service area.

On April 28, 2020, the JU filed comments supporting higher incentives, more program flexibility and a less prescriptive approach.

On July 16, 2020, the PSC issued Order Establishing Electric Vehicle Infrastructure Make Ready Program and Other Programs. The Order establishes a statewide EV Make Ready Program ("MRP") with a total budget capped at $701 million through 2025 including $206 million for the benefit of low/moderate income and environmental justice communities. The MRP is targeted at public/workplace chargers and Direct Current Fast Chargers and includes a Medium Duty and Heavy Duty MRP Pilot Program. The Order requires utilities offer a Fleet Assessment Service and creates three new NYSERDA Environmental Justice prize competitions totaling $85 million. The JU filed an MRP Participant Guide and Central Hudson filed its MRP Implementation Plan on August 17, 2020 and September 14, 2020, respectively. Utilities were required to develop an on-line EV supply application portal in a phased approach with Phase 1 and Phase 2 completed on October 16, 2020 and January 19, 2021, respectively. On December 4, 2020, Central Hudson filed tariffs for recovery of the EV MRP costs its Charging Proposal with the PSC. As directed by the Order, Central Hudson completed publication of load serving capacity maps tailored to support electric vehicle charging station siting by December 31, 2020 and is working with developers to determine the feasibility of future proofing plans from a grid and site perspective at each participating station. On December 17, 2020, the Commission issued a declaratory ruling that prize competitions are open to projects located anywhere in the State, but projects located outside of the investor-owned utility service territories must be funded incrementally and are not eligible to access the $85 million in Prize Competition funds established by the Make-Ready Order.

Energy Efficiency Proceeding

On December 13, 2018, the Commission issued an Order Adopting Accelerated Energy Efficiency Targets that established an interactive approach with immediate accelerated utility targets and budgets adopted for the years 2019-2020 and a process for developing utility-specific targets and budgets for the years 2021-2025, to be authorized by the Commission in 2019. The Order also develops processes to establish third party data access protocols, fuel switching, low-moderate income ("LMI") targets and future EAM development. Central Hudson's 2019-2020 targets did not increase since the 2018 Rate Order already reflects increased targets.

On April 1, 2019, the JU filed the New Efficiency New York filing. Central Hudson accepted the Commission's provisional electric and gas energy efficiency targets but proposed a higher incremental budget of $18 million and $1.1 million for electric and natural gas, respectively. The increase in incremental budget would align Central Hudson with the $/kWh and $/MMBtu average of other New York State utilities. The increase would be funded in part by unspent energy efficiency funds. Additionally, the utilities and NYSERDA were directed to begin implementation of a statewide ratepayer Low Income Plan in 2020, which is further discussed below. Finally, utilities were instructed to continue to file a System Energy Efficiency Plan, including quarterly progress reports**.**

On May 21, 2019, the JU filed an updated report, which included a discussion of heat pump program budgets and targets. Within the report, Central Hudson proposed a target installation of 11,934 residential and small commercial heat pumps with a budget of $30.2 million for the period 2020 through 2025. The 11,934 installation target results in savings of 253 GBtu, which is 39% lower than the target proposed by NYSERDA. Central Hudson's target was derived through a robust service territory specific analysis conducted by a third-party evaluation consultant.

On January 16, 2020, the Commission issued Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. The Commission estimates bill impacts of the contained budgets to average 0.7% of electric bills and 0.4% of gas bills. Unspent funds from prior periods will be leveraged to the extent possible to cover incremental expenditures. Additionally, companies were directed to use the 2020 budgets to reimburse NYSERDA for heat pump incentives paid within our service territory. The JU and NYSERDA jointly filed a Heat Pump Implementation Plan and Program Manual on March 16, 2020 in compliance with the Order.

The JU were directed to convene with NYSERDA and on a LMI Management Committee to develop a statewide LMI framework, including a customer-facing hub, as well as conducting LMI stakeholder engagement. On July 24, 2020, the JU filed a Statewide Low and Moderate Income Portfolio Implementation Plan and 2020 Stakeholder Input Companion Document with the Commission. On September 14, 2020, Staff issued a letter of approval to the JU confirming compliance of the Implementation Plan with the provisions of the Order contingent on Program Administrators following supplemental filings that address: (1) details of the operation of the Joint Management Committee, (2) development of a single application across Program Administrators, (3) a timeline detailing progress on milestones, (4) updates to the CEF/LMI Investment Plan, and (5) continuation of stakeholder engagement.

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, Transmission Planning, and the Clean Energy Standard Proceedings subheadings.

Renewable Energy Facility Host Community Benefit Program

On May 29, 2020, the Commission opened a new proceeding, Case 20-E-0249, to consider the establishment of a Host Community Benefit Program for municipalities within which major renewable energy facilities are constructed. Section eight of the ARECB Act provides that the PSC will establish a program through which the owners of major renewable energy facilities will fund a benefit for customers located in the municipalities that host the facilities in the form of a bill discount or credit, or a compensatory or environmental benefit for the impacted electric utility customers. The JU filed comments on how the Host Community Benefit should be structured on July 2, 2020, recommending additional collaboration to evaluate the various methods of implementing the Act and the merits of the various types of benefits that can be provided to communities.

Transmission Planning – Accelerated Renewable Energy Growth and Community Benefit

On May 14, 2020, the Commission 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 Commission to develop and implement plans for future investments in the electric grid to ensure it will support the State's aggressive climate goals. This Order reviews the legislative directives under the ARECB Act, immediately implements certain mandates, and outlines the additional actions the Commission plans to pursue to fulfill the objectives of the ARECB Act over the next several months.

Clean Energy Standard Proceedings

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.

On January 16, 2020, in an Order issued Modifying Tier 1 Renewable Procurements, the Commission directed NYSERDA to offer bidders an Index Renewable Energy Credit ("REC") price option in future Renewable Energy Standards ("RES") solicitations, beginning in 2020. NYSERDA filed its RES Program evaluation and Clean Energy Standard ("CES") Triennial Review report on June 1, 2020 in compliance with the CES reporting requirements.

On June 5, 2020, NYSERDA filed a petition regarding Clean Energy Resources Development and Incentive Program submitted in fulfillment of the ARECB Act requesting approval and funding to initiate and advance the "build ready" program through 2025. The program is expected to sustain six large scale renewable projects through 2025 with focus on utility scale solar and wind projects that may be paired with energy storage. The program focuses on reuse of previously developed and otherwise underutilized sites offered to renewable energy developers with bundled long-term REC contracts. The petition has been published for public comment.

On June 18, 2020, NYSERDA and DPS Staff submitted a whitepaper for public notice and comment, as well as Commission consideration on Clean Energy Procurements to Implement New York's CLCPA. The whitepaper identifies a proposed regulatory structure to address the CLCPA requirements for a renewable energy program and proposes to use the existing regulatory and procurement structure established under the Commission's CES to meet the 70 by 30 Target and adopts policy changes and other modifications to the CES to align with the CLCPA. A technical conference was held July 14, 2020 by NYSERDA and DPS Staff to discuss the regulatory framework proposed in the whitepaper. The JU submitted comments in response to the whitepaper and parties' preliminary comments on August 31, 2020.

On August 10, 2020, NYSERDA filed a petition with the Commission for the ability to convert generators currently under fixed-price REC contracts that have not yet achieved commercial operation to index-REC contracts; comments were filed by the JU on October 13, 2020.

On November 20, 2020, the Commission issued Order Authorizing Voluntary Modification of Certain Tier 1 Agreements which directed NYSERDA to issue a notice, within 60 days of the issuance of the Order, inviting all eligible developers to express interest in receiving an Index Renewable Energy Credit strike price offer. The Order also directed NYSERDA to provide a one-time option for eligible developers that have existing Fixed-Price Renewable Energy Credit contracts, but have not yet commenced commercial operation, to accept or reject, within 45 days, an offered Index Renewable Energy Credit strike price offer.

On August 13, 2020, the Commission approved the CES Phase 4 Implementation Plan Proposal submitted jointly by NYSERDA and Staff on April 16, 2020. The plan addressed the following implementation steps:

- NYSERDA was authorized to employ an index pricing structure in its future Tier 1 solicitations,
- the establishment of the process of setting market prices, performance criteria of auctions and the managing of REC vintages of the Tier 1 RECs that NYSERDA procures under this new structure,
- addressing unintentional impacts on the market for RECs imported to or exported from New York, and
- determining the impacts to the Value Stack Environmental Value tariffs.

NYSERDA filed the final Phase 4 Implementation plan that conformed changes required by the Phase 4 order on September 12, 2020.

Consolidated Billing for Community Distributed Generation

On December 12, 2019, the Commission issued an Order under Case 19-M-0463 in the Matter of Consolidated Billing for Distributed Energy Resources, adopting implementation of consolidated billing for CDG through a net crediting model, which will be available to all CDG projects, both existing and new. The Order requires CDG sponsors to guarantee a minimum CDG savings rate of 5.0% for participants, requires the net member credit to appear on customers' bills, requires the utility to provide the CDG sponsor with a sponsor payment which is equal to the total generation value less the net credits provided to subscribers, less a discount retained by the utility to recover costs for performing the consolidated billing function which the Order initially set at 1.0%. Central Hudson filed a Consolidated Billing Implementation Plan on February 3, 2020 that included an anticipated timeline for implementation of net crediting as well as a cost estimate. The Order directed utilities to file a Sponsor Net Crediting Agreement, Net Crediting Manual, tariff leaves and a Billing Upgrade Report which were filed on August 31, 2020, September 1, 2020 and November 24, 2020. On December 15, 2020, DPS Staff issued a CDG Banked Credits whitepaper intended to establish consistent banked credit distribution rules and processes across the utilities and avoid the forfeiture of credits when subscribers to projects either closes its utility account or terminates participation in the CDG project. Initial comments are due March 1, 2021 and Reply Comments are due March 15, 2021.

In the Matter of Utility Preparation & Response to Power Outages During the March 2018 Winter Storms

On March 14, 2018, following the March 2018 Nor'easter storms on March 2nd (Riley) and March 7th (Quinn), the PSC notified the chief executives of the state's major electric utility companies that an investigation into preparedness of and response to the two early March storms was underway, including all aspects of the Company's filed and approved emergency plans.

On April 18, 2019 the Commission released its 2018 Winter and Spring Storms Investigation Report ("Report") following its investigation. The Report has 94 recommendations that cover 18 topics, detailing actions to be taken to improve future storm preparation and restoration performance. The most significant recommendations address road clearing, damage assessments, estimated restoration times and communications with customers during the event. Utilities are directed to review each of the 94 recommendations and file a response with the Commission identifying whether the Commission should mandate, reject, or modify, in whole or in part, such recommendations. The Report cited Central Hudson's alleged failure to comply with a section of its ERP related to updates of its Interactive Voice Response ("IVR") within one hour of the Company's press releases. In an Order instituting proceeding and to show cause issued April 18, 2019, utilities were directed to show cause why the Commission should not pursue civil penalties pursuant to PSL §25 and/or administrative penalties, pursuant to PSL §25-a, for the apparent failure to follow their ERPs as approved and mandated by the ERP Order and Commission regulations. On May 20, 2019, Central Hudson responded to the show cause Order stating that the Commission should not penalize Central Hudson because the Company complied with its applicable 2016 ERP procedures, as approved by the Commission in Case 16-E-0635, which was in effect for the Riley and Quinn storms. Central Hudson's effective and approved ERP did not include a requirement that the IVR be updated within one hour after Central Hudson issued a press release.

Gas Plastic Fusion Proceeding

On May 18, 2018, the PSC issued an Order Adopting Further Improvements in Plastic Fusion Practices on Natural Gas Systems under Case 14-G-0212. The Order requires the filing of Quality Assurance/Quality Control Program and ongoing annual reports of all visually failed and visually passed fuses revealed and inspected. In a Department of Public Service Staff whitepaper issued February 12, 2019, Staff proposed Operator Qualification Best Practices for Commission adoption to address operator covered tasks as defined in 16NYCRR §255.3(9) on pipelines in New York State. The Company filed comments on Staff's whitepaper on May 28, 2019, supporting Staff's recommendations, including proposed timeframe for implementation and compliance as outlined in the collaborative process and continues to file monthly reports as directed in the Order.

Cybersecurity Protocols Proceeding

On June 14, 2018, the PSC instituted Proceeding on Motion of the Commission Regarding Cybersecurity Protocols and Protections in the Energy Market Place, under Case 18-M-0376. The Order was established to ensure that appropriate protections are being implemented and followed throughout the industry.

On February 4, 2019, the JU filed a Petition for Approval of the Business-to-Business Process Used to Formulate a Data Security Agreement ("DSA") and for Affirming the JUs' Authority to Require and Enforce Execution of the DSA by Entities Seeking Access to the Utility Customer Data or Utility Systems. The JUs proposed cybersecurity standards that should be applicable to any entity that electronically exchanges data with the utility, including energy service companies, distributed energy resource suppliers, direct customers and their applicable contractors. On October 17, 2019, the Commission issued an Order Establishing Minimum Cybersecurity and Privacy Protections. The Order adopts minimum cybersecurity and data privacy requirements for entities that receive from, or exchange customer data with, utilities on an electronic basis other than by mail. The JUs filed a revised DSA and Self Attestation on January 9, 2020 and executed agreements with each Energy Service Entity a DSA in compliance with the Order. The Commission granted several extension requests to file a DSA for State entities. The JU filed DSAs for State entities on July 13, 2020 and August 21, 2020. The Commission will continue to develop cybersecurity and data privacy requirements and modify or expand upon them in the future, as appropriate. The Commission will continue to develop cybersecurity and data privacy requirements and modify or expand upon them in the future, as appropriate.

Clean Energy Standard Proceedings

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. On March 15, 2018, the Commission ordered modifications to the existing Maintenance Tier program, which applies only to eligible, preexisting renewable facilities. The modifications include expanding the funding capability for already-built renewable energy projects under the program in cases of need, increasing the size threshold for eligible existing hydroelectric facilities from 5 MW up to 10 MW, and lowering regulatory burdens making it easier to participate in the program if the facility is under economic duress. This will facilitate New York State meeting its renewable targets by 2030. Additionally, in 2018, NYSERDA awarded $1.4 billion for 26 new large-scale renewable energy projects from the 2017 Renewable Energy Standard Solicitation. The awarded projects are located throughout New York State and include 22 solar farms, three wind farms, and one hydroelectric project. These projects are expected to be operational by 2022 and, once operational, will add more than 1,380 MW of renewable capacity. NYSERDA expects these projects to create more than 3,000 short and long term jobs in construction, operations and maintenance. On December 13, 2018, the PSC issued an Order Approving Phase 3 Implementation Plan. The Order directs NYSERDA to offer expiring RECs at a reduced rate to LSEs equal to the current year price.

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.

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 and includes renewable energy and emission reduction goals in New York State, which would be the most aggressive in the nation. The Act defines targets for 70 percent renewable electricity by 2030 and 100 percent 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 green-house gas emissions 40% (from 1990 baseline levels) by 2030 and 85% by 2050 and 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 DEC as an alternative compliance mechanism for sources subject to the emissions limits.

A 22-member Climate Action Council, comprised of technical experts appointed by the governor and led by NYSERDA and the DEC, was established and charged with preparing and approving a scoping plan within 3 years outlining recommendations to attain the statewide greenhouse gas 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 related to the program.

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 recent 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.

Community Choice Aggregation

On January 18, 2018 and March 16, 2018, the PSC approved Community Choice Aggregation ("CCA") programs filed by Good Energy and Joule Assets, Inc. respectively, subject to certain modifications to their implementation plans and filing of a final Data Protection Plan. CCA programs provide municipalities with the opportunity to aggregate electric and/or gas supply on behalf of their residents and small businesses on an opt-out basis. The CCA framework requires that one or more municipalities, or their designee in the role of a CCA administrator, file an Implementation Plan and Data Protection Plan for Commission approval. To date, twelve communities within the Central Hudson service territory have each exercised their Municipal Home Rule Law authority to initiate a CCA program. Additional communities may pass local laws in the future to join or establish a CCA. Central Hudson is working with Good Energy and Joule Assets as they work to develop programs for Central Hudson's customers.

Utility Energy Registry Proceeding

On April 19, 2018, the PSC issued an Order Adopting Utility Energy Registry under Case 17-M-0315. The Order requires Central Hudson and the other New York utilities to provide customer data for the Utility Energy Registry ("UER") subject to the privacy standards set forth in the UER. Datasets are to be submitted every six months January-June and July-December within 30 days of the close of each semi-annual period. The data portal was made available by NYSERDA for general use in September 2019. The purpose of the UER is to make community-based energy consumption data more readily available for local planning, market research and CCA development with a goal of promoting actions to adopt more efficient and cleaner energy use patterns and strategies. Central Hudson has provided Company data for 2016, 2017, 2018 and 2019. On December 30, 2019, NYSERDA filed a UER Status Report prepared by Climate Action Associates, LLC to report on the progress of UER's implementation and operation, including the demands for, uses of, and benefits of UER data, as well as the need for refinements. On January 10, 2020 the Commission issued a notice soliciting comments on the UER report. JU and party comments were filed March 23, 2020.

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 pipeline. Because Central Hudson's transmission lines are intrastate, NYS PSC proceedings will also be required for Central Hudson regarding the implementation of this rule. Central Hudson continues to monitor this proceeding and expects that any associated compliance costs would be recovered in rates.

Central Hudson Management and Operations Audit

In a July 16, 2018 Order, the Commission approved Central Hudson's Revised Audit Implementation Plans filed on December 14, 2017 and June 26, 2018. The Company's implementation plans address the Overland Final Audit Report released October 24, 2017 that included 55 recommendations. Central

Hudson rejected eight recommendations in its implementation plan. The Order directs the Company to file updates on its progress with the recommendations no less frequently than every four months. Central Hudson's most recent update was filed on November 13, 2020 and reported that it considered 45 of the 47 audit recommendations complete and continues to work on implementation of the remaining two recommendations. To date, 44 recommendations have been accepted by Staff.

Uniform Statewide Customer Satisfaction Survey
On October 18, 2018 in Case 15-M-0566 the Commission issued an Order Authorizing Implementation of a Pilot Statewide Customer Satisfaction Survey. The pilot survey was implemented on January 1, 2019. However, Central Hudson also continued its existing customer satisfaction survey.

On June 15, 2020, Staff submitted its Report on the Uniform Statewide Customer Satisfaction Pilot Survey and recommended the Commission modify the Pilot Survey to make it more standardized and consistent across utilities and to continue emailing surveys on a permanent basis in order to collect sufficient data for benchmarking purposes in each utility's next rate case. In response to a July 8, 2020 notice for public comment on Staff's report, the JU submitted comments in support of the report recommendations on September 9, 2020.

Changes to the Retail Access Energy Market
On December 12, 2019, the Commission issued Order Adopting Changes to the Retail Access Energy Market and Establishing Further Process. The provisions of the Order strengthen protections for residential and small commercial (mass-market) customers in the retail energy market. The Order increases Energy Services Companies ("ESCO") accountability by enhancing eligibility criteria, improves transparency of ESCO product and pricing information and prohibits ESCO product offerings that lack energy service-based values by restricting the types of products and services ESCOs are allowed to offer mass-market customers.

Beginning in February 2020, any product marketed by an ESCO must meet one of the following criteria with limited exceptions: 1) it must guarantee savings compared to the utility; 2) it must be a fixed rate product with a price limit; or 3) it must be a renewably sourced product. The Order directs utilities to publish their 12-month trailing average utility supply rate within 15 days of the close of the quarter, starting with the quarter ended December 31, 2019. The Order also directs Staff and the utilities to develop individualized billing plans that set forth timely and cost-effective pathways towards maximizing the dissemination of useful price comparison information to customers. The Order requires ESCOs to submit a new application to serve customers within 90 days that provides information on marketing methods, categories of approved commodity products it will offer, complaint history, security breaches, history of bankruptcy, dissolution, merger or acquisition activities, proof of financial assurances and officer certification of compliance with applicable laws and regulations.

On September 18, 2020, the Commission issued an Order on Rehearing, Reconsideration and Providing Clarification in Case 98-M-1343. The Order establishes new enrollment guidelines for products offered to mass-market customers (guaranteed savings reconciled on an annual basis, "no more than" pricing relative to utility supply service and renewably sourced electric commodity product). The Order is effective February 15, 2021 for ESCOs enrolling customers. Utilities are required to update their Uniform Business Practices Manuals to conform to these changes and file revised tariffs, as necessary. On November 20, 2020, the DPS Staff issued Updated Guidance Regarding ESCO Eligibility Review to Reflect the directives and revised timelines of the Commission's Order on Rehearing, Reconsideration, and Providing Clarification issued on September 18, 2020. Several ESCOs are participating in this program and have filed applications with the Commission.

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 "anticipates," "intends," "estimates," "believes," "projects," "expects," "plans," "assumes," "seeks," 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 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 Quarterly and 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.

ANNUAL FINANCIAL REPORT SUPPLEMENT

Holding Company Regulation

CH Energy Group is a "holding company" under Public Utility Holding Company Act of 2005 ("PUHCA 2005") because of its ownership interests in Central Hudson, CHEC, CHET, and CHGT. CH Energy Group, however, is exempt from regulation as a holding company under PUHCA 2005, because it derives substantially all of its public utility company revenues from business conducted within a single state, the State of New York. At the present time, CH Energy Group cannot predict whether and when its circumstances may change such that it no longer qualifies for exemption from PUHCA 2005.

Central Hudson

Central Hudson (the "Company") is a New York State corporation formed in 1926. Central Hudson purchases, sells at wholesale and retail, and distributes electricity and natural gas at retail in portions of New York State. Central Hudson also generates a small portion of its electricity requirements.

Central Hudson serves a territory comprising of approximately 2,600 square miles in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and about the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories. The number of full time and temporary Central Hudson employees at December 31, 2020 was 1,061.

Central Hudson's territory reflects a diversified economy, including manufacturing industries, governmental agencies, public and private institutions, wholesale and retail trade operations, research firms, farms and resorts.

Regulation

Central Hudson is subject to regulation as follows:

- PSC – services rendered (including the rates charged), major transmission facility siting, accounting treatment of certain items, and issuance of securities. See Note 4 – "Regulatory Matters" of the Company's 2020 Annual Financial Report.
- FERC (under the Federal Power Act) – accounting and the acquisition and disposition of certain property.
- North American Electric Reliability Corporation – ownership, operation and use of a bulk power system.
- DEC – ownership, operation and use of hydroelectric facilities and environmental site investigation and remediation activities.
- Pipeline and Hazardous Materials Safety Administration – ownership, operation and use of gas pipeline system.
- NYISO – Daily activities, such as purchases and sales of energy and energy-related products, are subject to compliance monitoring and enforcement by the NYISO in accordance with the Market Services Tariff.
- United States Army Corps of Engineers – Construction, repair, replacement of gas or electric lines or facilities that may cross or are located within a federally protected wetland or water body.

Environmental Quality Regulation

Central Hudson is subject to regulation by federal, state, and local authorities with respect to the environmental effects of their operations. Environmental matters may expose Central Hudson to potential liability, which, in certain instances, may be imposed without regard to fault or may be premised on historical activities that were lawful at the time they occurred.

Central Hudson monitors its activities in order to determine their impact on the environment and to comply with applicable environmental laws and regulations.

The principal environmental areas relevant to Central Hudson (air, water and industrial and hazardous wastes) are described below. Unless otherwise noted, all required permits and certifications have been obtained by the applicable company. Management believes that Central Hudson was in material compliance with these permits and certifications during 2020. For further discussions related to environmental matters see Note 14 – "Commitments and Contingencies".

Air Quality

The Clean Air Act Amendments of 1990 address attainment and maintenance of national air quality standards and impact Central Hudson electric generating facilities in South Cairo and Coxsackie, NY.

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control and requires facilities that discharge waste or storm water into the waters of the United States to obtain permits. Central Hudson has permits regulating pollutant discharges for relevant locations.

Industrial & Hazardous Substances and Wastes

Central Hudson is subject to federal, state and local laws and regulations relating to the use, handling, storage, treatment, transportation, and disposal of industrial, hazardous, and toxic wastes. See Note 14 − "Commitments and Contingencies" under the caption "Environmental Matters" for additional discussion regarding, among other things, Central Hudson's former MGP facilities, Eltings Corners and Little Britain Road.

Rates

PSC – Costs of service, both for electric and natural gas delivery service and supply costs, are recovered from customers through PSC approved tariffs, subject to a standard of prudency. For further information, see Note 1 – "Summary of Significant Accounting Policies" under the caption "Rates, Revenues, and Adjustment Mechanisms" and Note 4 – "Regulatory Matters" under the caption "2018 Rate Order and Related Proceedings" of the Company's 2020 Annual Report.

- Customer classes – Residential and non-residential.
- Retail electricity services – Various service classifications covering delivery service and full service (which includes electricity supply).
- Retail natural gas services – Various service classifications covering transport, retail access service, and full service (which includes natural gas supply).
- RDMs – Central Hudson's rates include RDMs which are intended to minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented by breaking the link between energy sales and utility revenues and profits. Central Hudson's RDMs allow the Company to recognize electric delivery revenues and natural gas sales per customer at the levels approved in rates for most of Central Hudson's electric and natural gas customer classes.

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

FERC – Transmission rates and rates for electricity sold for resale which involve interstate commerce.

During 2020, the average price of electricity for full service customers was 16.13 cents per kWh, which includes commodity and surcharges, as compared to an average of 15.67 cents per kWh in 2019. The average delivery only price in 2020 was 8.36 cents per kWh compared with 7.39 cents per kWh in 2019. The increase in delivery price was primarily due to an increase in base delivery revenue and collection of specified accumulated deferred balances, both pursuant to the 2018 Rate Order. This increase in delivery price was partially offset by lower commodity costs for full-service load.

During 2020, the average price of natural gas for full-service customers was $14.86 per Mcf, which includes commodity and surcharges, as compared to an average of $14.32 per Mcf in 2019. The average delivery only price for natural gas for retail and full service in 2020 was $8.90 per Mcf compared with $7.57 per Mcf in 2019. The increase in delivery price was primarily due to an increase in the base delivery revenue pursuant to the 2018 Rate Order, an increase in weather normalization adjustment collections resulting from warmer than normal weather conditions, and an increase in the collection of base delivery revenue resulting from a shortfall as compared to the regulatory target. This increase in delivery price was partially offset by lower commodity costs for full-service load.

Cost Adjustment Clauses and RDMs: For information regarding Central Hudson's purchased electric and natural gas cost adjustment mechanisms and RDMs, see Note 1 – "Summary of Significant Accounting Policies" under the caption "Rates, Revenues, and Adjustment Mechanisms."

Electric

Central Hudson owns hydroelectric and gas turbine generating facilities as described below.

Type of Electric Generating Plant	Year Placed in Service/Refurbished	MW(1) Net Capability
Hydroelectric (3 stations)	1920-2019	22.4
Gas turbine (2 stations)	1969-1996	42.5
Total		64.9

(1) Reflects the name plate rating of Central Hudson's electric generating plants and therefore does not include firm purchases or sales.

Central Hudson owns substations having an aggregate transformer capacity of 5.7 million kilovolt amperes. Central Hudson's electric transmission system consists of 580 pole miles of line. The electric distribution system consists of approximately 7,200 pole miles of overhead lines and 1,600 trench miles of underground lines, as well as customer service lines and meters.

Electric Load and Capacity

Central Hudson's maximum one-hour demand for electricity within its own territory for the year ended December 31, 2020, occurred on July 27, 2020, and amounted to 1,142 MW. Central Hudson's all-time highest peak electric demand reached 1,295 MW on August 2, 2006. Central Hudson's current maximum one-hour demand for electricity within its own territory for the 2020-2021 winter capability period occurred to date on December 16, 2020, and amounted to 843 MW.

Central Hudson owns minimal generating capacity and relies on purchased capacity and energy from third-party providers to meet the demands of its full service customers. For more information, see Note 14 – "Commitments and Contingencies."

Natural Gas

Central Hudson's natural gas system consists of 165 miles of transmission pipelines and 1,300 miles of distribution pipelines, as well as customer service lines and meters. For the year ended December 31, 2020, the total amount of natural gas purchased by Central Hudson from all sources was 10,352,132 Mcf.

The peak daily demand for natural gas of Central Hudson's customers for the year ended December 31, 2020, occurred on December 18, 2020 and was 111,074 Mcf. The all-time highest winter period daily peak for Central Hudson of 141,141 Mcf occurred on January 6, 2018. Current peak demand for the 2020-2021 heating season to date occurred on December 18, 2020 and was 111,074 Mcf. Central Hudson's firm peak day natural gas capability in 2020-2021 heating season is 155,312 Mcf.

Purchased Power and Generation Costs

For the year ended December 31, 2020, the sources and related costs of purchased electricity and electric generation for Central Hudson were as follows:

Sources of Energy	Aggregate Percentage of Energy Requirements		Costs in 2020 (In Thousands)
Purchased Electricity	97.6%	$	131,862
Hydroelectric and Other	2.4%		73
Deferred Electricity Cost			4,195
Total	100.0%	$	136,130

Other Central Hudson Matters

Labor Relations: Central Hudson has four agreements with Local 320 of the International Brotherhood of Electrical Workers for its 599 unionized employees. These agreements cover construction and maintenance employees, customer service representatives, service workers, clerical and system operation employees (excluding persons in managerial, professional, or supervisory positions). One agreement is in effect through March 31, 2021 covering approximately 4.3% of total unionized employees, while the other three agreements are in effect through April 30, 2022.

Property Additions: During the three-year period ended December 31, 2020, Central Hudson made gross property additions of $665.2 million and property retirements and adjustments of $82.3 million, resulting in a net increase (including construction work in progress) in gross utility plant of $582.9 million, or 26.6%.

Other Environmental Matters: Central Hudson is also subject to regulation with respect to other environmental matters, such as noise levels, protection of vegetation and wildlife, and limitations on land use, and is in compliance with regulations in these areas.

Regarding environmental matters, except as described in Note 14 - "Commitments and Contingencies" under the caption "Environmental Matters," neither CH Energy Group nor Central Hudson are involved as defendants in any material litigation, administrative proceeding, or investigation and, to the best of their knowledge, no such matters are threatened against any of them.

Environmental Expenditures

2020 actual and 2021 estimated expenditures attributable in whole or in substantial part to environmental considerations are detailed in the table below (In Millions):

	2020	2021
Central Hudson	$ 11.9	$ 21.7

The increase in 2021 estimated expenditures relates primarily to ongoing remediation activities at the North Water Street MGP remediation site. For further discussion of these activities, see Note 14 – “Commitments and Contingencies” under caption “Site Investigation and Remediation Program”.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2020

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-32576

ITC HOLDINGS CORP.

(Exact Name of Registrant as Specified in Its Charter)

Michigan	**32-0058047**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

27175 Energy Way
Novi, Michigan 48377
(Address Of Principal Executive Offices, Including Zip Code)
(248) 946-3000
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
None	None	None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☑ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☑ * (Note: the Registrant is a voluntary filer and has not been subject to the filing requirements under Section 13 or 15(d) of the Securities Exchange Act of 1934 for the preceding 12 months.)

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller Reporting Company	Emerging growth company
☐	☐	☑	☐	☐

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock held by non-affiliates on June 30, 2020 was $0.

All shares of outstanding common stock of ITC Holdings Corp. are held by its parent company, ITC Investment Holdings Inc., which is an indirect subsidiary of Fortis Inc. There were 224,203,112 shares of common stock, no par value, outstanding as of February 11, 2021.

DOCUMENTS INCORPORATED BY REFERENCE

None

ITC Holdings Corp.

Form 10-K for the Fiscal Year Ended December 31, 2020

INDEX

		Page
PART I		7
Item 1.	Business	7
Item 1A.	Risk Factors	15
Item 1B.	Unresolved Staff Comments	22
Item 2.	Properties	22
Item 3.	Legal Proceedings	22
Item 4.	Mine Safety Disclosures	23
PART II		23
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	23
Item 6.	Selected Financial Data	23
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	23
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	40
Item 8.	Financial Statements and Supplementary Data	42
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	86
Item 9A.	Controls and Procedures	86
Item 9B.	Other Information	86
PART III		86
Item 10.	Directors, Executive Officers and Corporate Governance	86
Item 11.	Executive Compensation	90
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	118
Item 13.	Certain Relationships and Related Transactions, and Director Independence	119
Item 14.	Principal Accountant Fees and Services	121
PART IV		122
Item 15.	Exhibits and Financial Statement Schedules	122
Item 16.	Form 10-K Summary	134
Signatures		135

Unless otherwise noted or the context requires, all references in this report to:

ITC Holdings Corp. and its subsidiaries

- “ITC Great Plains” are references to ITC Great Plains, LLC, a wholly-owned subsidiary of ITC Holdings;
- “ITC Holdings” are references to ITC Holdings Corp. and not any of its subsidiaries;
- “ITC Interconnection” are references to ITC Interconnection LLC, a wholly-owned subsidiary of ITC Holdings;
- “ITC Midwest” are references to ITC Midwest LLC, a wholly-owned subsidiary of ITC Holdings;
- “ITCTransmission” are references to International Transmission Company, a wholly-owned subsidiary of ITC Holdings;
- “METC” are references to Michigan Electric Transmission Company, LLC, a wholly-owned subsidiary of MTH;
- “MISO Regulated Operating Subsidiaries” are references to ITCTransmission, METC and ITC Midwest together;
- “MTH” are references to Michigan Transco Holdings, LLC, the sole member of METC and a wholly-owned subsidiary of ITC Holdings;
- “Regulated Operating Subsidiaries” are references to ITCTransmission, METC, ITC Midwest, ITC Great Plains and ITC Interconnection together; and
- “Company”, “we,” “our” and “us” are references to ITC Holdings together with all of its subsidiaries.

Other definitions

- “2017 Omnibus Plan” are references to the Company’s February 27, 2017 long-term equity incentive plan as amended July 10, 2017 and February 4, 2020;
- “ACPB” are references to an award under the annual corporate performance bonus plan;
- “ADIT” are references to accumulated deferred income tax;
- “AFUDC” are references to an allowance for funds used during construction;
- “ALJ” are references to an administrative law judge;
- “Ancillary Services Agreement” are references to the Amended and Restated Purchase and Sale Agreement for Ancillary Services entered into by METC and Consumers Energy dated as of April 29, 2002;
- “AOCI” are references to accumulated other comprehensive income or (loss);
- “ARAM” are references to the average rate assumption method of amortization;
- “CIA” are references to the Coordination and Interconnection Agreement entered into by ITCTransmission and DTE Electric dated as of February 28, 2003;
- “Consumers Energy” are references to Consumers Energy Company, a wholly-owned subsidiary of CMS Energy Corporation;
- “COVID-19” are references to the Coronavirus disease that the World Health Organization declared a pandemic in March 2020;
- “D.C. Circuit Court” are references to the U.S. Court of Appeals for the District of Columbia Circuit;
- “DCF” are references to discounted cash flow;
- “DOE” are references to the Department of Energy;
- “DTE Electric” are references to DTE Electric Company, a wholly-owned subsidiary of DTE Energy;
- “DTE Energy” are references to DTE Energy Company;

- “DTIA” are references to the Distribution-Transmission Interconnection Agreement entered into by ITC Midwest and IP&L dated as of December 17, 2007 and amended and restated effective as of December 1, 2016;
- “DT Interconnection Agreement” are references to the Amended and Restated Distribution-Transmission Interconnection Agreement entered into by METC and Consumers Energy dated April 1, 2001 and most recently amended and restated effective as of January 1, 2015;
- “Easement Agreement” are references to the Amended and Restated Easement Agreement entered into by METC and Consumers Energy dated April 29, 2002 and as further supplemented;
- “Eiffel” are references to Eiffel Investment Pte Ltd, a private limited company duly organized and validly existing under the laws of Singapore that is the GIC subsidiary that is a minority investor in ITC Investment Holdings and successor to Finn Investment Pte Ltd;
- “ESPP” are references to the Fortis Amended and Restated 2012 Employee Share Purchase Plan;
- “Exchange Act” are references to the Securities Exchange Act of 1934, as amended;
- “Executive Omnibus Plan” are references to the Company’s February 4, 2020 long-term equity incentive plan;
- “FASB” are references to the Financial Accounting Standards Board;
- “FERC” are references to the Federal Energy Regulatory Commission;
- “Formula Rate” are references to a FERC-approved formula template used to calculate an annual revenue requirement;
- “Fortis” are references to Fortis Inc.;
- “FortisUS” are references to FortisUS Inc., an indirect subsidiary of Fortis;
- “FPA” are references to the Federal Power Act;
- “GAAP” are references to accounting principles generally accepted in the United States of America;
- “Generator Interconnection Agreement” are references to the Amended and Restated Generator Interconnection Agreement entered into by Consumers Energy and METC dated as of April 29, 2002 and most recently amended effective as of November 1, 2018;
- “GIAs” are references to generator interconnection agreements;
- “GIC” are references to GIC Private Limited;
- “GIOA” are references to the Generator Interconnection and Operation Agreement entered into by DTE Electric and ITCTransmission dated as of February 28, 2003;
- “Initial Complaint” are references to a November 2013 complaint to the FERC under Section 206 of the FPA regarding the base ROE;
- “ITC Investment Holdings” are references to ITC Investment Holdings Inc., a majority owned indirect subsidiary of Fortis in which GIC has an indirect minority ownership interest;
- “IP&L” are references to Interstate Power and Light Company, an Alliant Energy Corporation subsidiary;
- “IRS” are references to the Internal Revenue Service;
- “ISO” are references to Independent System Operators;
- “KCC” are references to the Kansas Corporation Commission;
- “kV” are references to kilovolts (one kilovolt equaling 1,000 volts);
- “kW” are references to kilowatts (one kilowatt equaling 1,000 watts);
- “LBA” are references to a Local Balancing Authority;

- "LGIA" are references to the Large Generator Interconnection Agreement entered into by ITC Midwest, IP&L, and MISO dated as of December 20, 2007 and amended as of August 2, 2017;
- "LIBOR" are references to the London Interbank Offered Rate;
- "May 2020 Order" are references to an order issued by the FERC on May 21, 2020 regarding MISO ROE Complaints;
- "MECS" are references to the Michigan Electric Coordinated Systems;
- "Merger Agreement" are references to the agreement and plan of merger between Fortis, FortisUS, Element Acquisition Sub, Inc. and ITC Holdings for the merger;
- "Mid-Kansas" are references to Mid-Kansas Electric Company LLC;
- "Mid-Kansas Agreement" are references to an Amended and Restated Maintenance Agreement entered into by Mid-Kansas and ITC Great Plains dated as of August 24, 2010, and most recently amended effective as of March 6, 2017;
- "MISO" are references to the Midcontinent Independent System Operator, Inc., a FERC-approved RTO which oversees the operation of the bulk power transmission system for a substantial portion of the Midwestern United States and Manitoba, Canada, and of which ITCTransmission, METC and ITC Midwest are members;
- "MISO ROE Complaints" are references to the Initial Complaint and the Second Complaint;
- "MOA" are references to the Master Operating Agreement entered into by ITCTransmission and DTE Electric dated as of February 28, 2003;
- "Moody's" are references Moody's Investor Service, Inc.;
- "MVPs" are references to multi-value projects, which have been determined by MISO to have regional value while meeting near-term system needs;
- "MW" are references to megawatts (one megawatt equaling 1,000,000 watts);
- "NERC" are references to the North American Electric Reliability Corporation;
- "NOLs" are references to net operating loss carryforwards for income taxes;
- "NOPR" are references to a Notice of Proposed Rulemaking issued by the FERC;
- "November 2018 Order" are references to an order issued by the FERC on November 15, 2018 regarding MISO ROE Complaints;
- "November 2019 Order" are references to an order issued by the FERC on November 21, 2019 regarding MISO ROE Complaints;
- "NYSE" are references to the New York Stock Exchange;
- "Operating Agreement" are references to the Amended and Restated Operating Agreement entered into by Consumers Energy and METC dated as of April 29, 2002;
- "OSA" are references to the Operations Services Agreement for 34.5 kV Transmission Facilities entered into by ITC Midwest and IP&L effective as of January 1, 2011;
- "PBU" are references to a performance-based unit;
- "PCBs" are references to polychlorinated biphenyls;
- "PJM" are references to PJM Interconnection LLC, a FERC-approved RTO which oversees the operation of the bulk power transmission system for a substantial portion of the Eastern United States, and of which ITC Interconnection is a member;
- "ROE" are references to return on equity;
- "RSGM" are references to the Reverse South Georgia Method of amortization;
- "RTO" are references to Regional Transmission Organizations;

- “SBU” are references to a service-based unit;
- “SEC” are references to the Securities and Exchange Commission;
- “Second Complaint” are references to an additional complaint filed on February 12, 2015 with the FERC under Section 206 of the FPA regarding the base ROE;
- “September 2016 Order” are references to an order issued by the FERC on September 28, 2016 regarding the Initial Complaint;
- “Shareholders Agreement” are references to the Shareholders’ Agreement, dated as of October 14, 2016 by and among the Company, ITC Investment Holdings, FortisUS, Eiffel (as successor to Finn Investment Pte Ltd), and any other person that becomes a shareholder of ITC Investment Holdings pursuant to such agreement;
- “SOFR” are references to the Secured Overnight Financing Rate;
- “SPP” are references to Southwest Power Pool, Inc., a FERC-approved RTO which oversees the operation of the bulk power transmission system for a substantial portion of the South Central United States, and of which ITC Great Plains is a member;
- “S&P” are references to S&P Global Ratings;
- “TCJA” are references to the Tax Cuts and Jobs Act of 2017, a comprehensive tax reform bill enacted on December 22, 2017;
- “TO” are references to transmission owner;
- “ULCS” are references to Utility Lines Construction Services, LLC; and
- “USD” are references to the United States dollar

PART I

ITEM 1. *BUSINESS.*

Overview

Our business consists primarily of the electric transmission operations of our Regulated Operating Subsidiaries. ITC Holdings is a wholly-owned subsidiary of ITC Investment Holdings. Fortis owns a majority indirect equity interest in ITC Investment Holdings, with GIC holding an indirect equity interest of 19.9%. Through our Regulated Operating Subsidiaries, we own and operate high-voltage electric transmission systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to our transmission systems.

ITC Holdings provides safe and reliable electric transmission service to connect consumers to cleaner and more cost-effective energy resources. ITC Holdings is leading the way in making investments in a modernized grid to maintain reliability and accommodate future demands as our economy and lifestyles become increasingly dependent on electricity. We are actively involved in planning an integrated energy network to serve our customers, communities and the greater grid.

Our business strategy is focused on owning, operating, maintaining and investing in transmission infrastructure and grid solutions in order to enhance system reliability, protect critical infrastructure, reduce transmission constraints, interconnect new renewable generation resources, expand access to electricity markets and lower the overall cost of delivered energy.

Our Regulated Operating Subsidiaries earn revenues for the use of their electric transmission systems by their customers, which include investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, our Regulated Operating Subsidiaries are subject to rate regulation only by the FERC, and our cost-based rates are discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism."

Development of Business

As we move toward a cleaner and more electrified economy, the power grid is experiencing a transformation. Technology deployment and innovation are occurring at an accelerated rate within our industry, so ITC Holdings is actively identifying and investing in infrastructure required to meet evolving system needs and energy policy objectives. Our long-term growth plan includes ongoing investments in our current regulated transmission systems and the identification of incremental strategic projects primarily located in and around our service territories.

We expect to invest approximately $3.9 billion from 2021 through 2025 at our Regulated Operating Subsidiaries. Included in this amount are capital expenditures to: (1) maintain and replace our current transmission infrastructure including enhancing system integrity and reliability and accommodating load growth; (2) upgrade physical and technological grid security; (3) promote the transformation of the generation fleet to cleaner and more sustainable resources through required interconnections and transmission build-out; and (4) develop and build regional transmission infrastructure.

Refer to "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Investment and Operating Results Trends" for additional details about our long-term capital investments. Refer to the discussion of risks associated with our strategic investment opportunities in "Item 1A Risk Factors."

Operations

As transmission-only companies, our Regulated Operating Subsidiaries function as conduits, allowing for power from generators to be transmitted to local distribution systems either entirely through our Regulated Operating Subsidiaries' own systems or in conjunction with neighboring transmission systems. Third parties then transmit power through these local distribution systems to end-use consumers. The transmission of electricity by our Regulated Operating Subsidiaries is a central function to the provision of electricity to residential, commercial and industrial end-use consumers. The operations performed by our Regulated Operating Subsidiaries fall into the following categories:

- asset planning;

- engineering;
- asset protection and performance;
- cyber security operations center; and
- real time operations.

Asset Planning

The Asset Planning group uses detailed system models and load forecasts to develop our system expansion capital plans. Expansion capital plans identify projects that address reliability issues and/or produce economic savings for customers by eliminating constraints.

The Asset Planning group submits projects into the MISO and SPP planning processes. As the regional planning authorities, MISO and SPP administer open and transparent processes through which the submitted Asset Planning group plans are vetted. MISO and SPP produce transmission expansion plans, which include projects to be constructed by their members, including our MISO Regulated Operating Subsidiaries and ITC Great Plains.

Engineering

The Engineering group is composed of the Design, Capital Projects and Asset Management teams. The Engineering group works with outside contractors to perform various aspects of our design, construction and maintenance, but retains internal technical experts who have experience with respect to the key elements of the transmission system such as substations, lines, equipment and protective relaying systems.

Design — The Design team is responsible for the design of our transmission systems and setting the standards for equipment used on our systems.

Capital Projects — The Capital Projects team is responsible for project and construction management for capital projects, which includes the construction of new transmission infrastructure as well as asset renewal projects.

Asset Management — The Asset Management team performs the following activities:

- manages our vegetation management program;
- provides engineering technical support to the field;
- specifies, maintains and troubleshoots the protection and controls system that is used to protect and monitor our transmission infrastructure; and
- develops and tracks preventative maintenance to promote safe and reliable systems adhering to mandatory requirements of the NERC and FERC.

By performing preventive maintenance on our assets, we can minimize the need for reactive maintenance, resulting in improved reliability and cost savings for our customers. Our Regulated Operating Subsidiaries contract with ULCS, which is a division of Asplundh Tree Expert Co., to perform the majority of their maintenance. The agreement with ULCS provides us with access to an experienced and scalable workforce with knowledge of our system at an established rate.

Asset Protection and Performance

The Asset Protection and Performance group is responsible for safety, human performance, security, and emergency preparedness and response. Given the inherent hazardous nature of the utilities industry, we proactively work to ensure that all personnel are free to perform in a safe and secure environment. Our focus is not to compromise the safety of our employees, contractors or the public in the course of providing the most reliable electricity transmission services. We maintain a safety program that includes proactive measures rooted in human performance tools to achieve that focus. Our emergency response plans ensure that we are prepared for a crisis and can maintain continuity of our business and service during said crisis. We operate a security command center from our headquarters facility in Michigan that monitors our most critical assets on a continuous basis. The security command center also gathers intelligence and works with our government and industry partners to prevent threats to our assets.

Cyber Security Operations Center

The Cyber Security Operations Center is responsible for reducing the risk of cyber-attacks, data breaches, and data theft by deploying advanced monitoring techniques, technical controls, and administrative policies. As the threat landscape becomes increasingly sophisticated and expansive, we continue to educate our user community and advance our protections against ongoing cyber threats.

Real Time Operations

System Operations — From our operations facilities in Michigan, transmission system operators continuously monitor the performance of the transmission systems of our Regulated Operating Subsidiaries, using software and communication systems to perform analysis to plan for contingencies and maintain security and reliability following any unplanned events on the system. Transmission system operators are also responsible for the switching and protective tagging function, taking equipment in and out of service to ensure capital construction projects and maintenance programs can be completed safely and reliably.

Local Balancing Authority Operator — Under the functional control of MISO, ITCTransmission and METC operate their electric transmission systems as a combined LBA area, known as MECS. From our operations facilities in Michigan, our employees perform the LBA functions as outlined in MISO's Balancing Authority Agreement. These functions include actual interchange data administration and verification as well as MECS LBA area emergency procedure implementation and coordination. Besides ITCTransmission and METC, our other Regulated Operating Subsidiaries are not responsible for LBA functions for their respective assets.

Operating Contracts

Our Regulated Operating Subsidiaries have various operating contracts, including numerous interconnection agreements with generation and transmission providers that address terms and conditions of interconnection. The following significant agreements exist at our Regulated Operating Subsidiaries:

ITCTransmission

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

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

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

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

METC

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

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

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

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

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

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

ITC Midwest

IP&L operates an electric distribution system that interconnects with ITC Midwest's transmission system. ITC Midwest is a party to a number of operating contracts with IP&L that govern the operations and maintenance of their respective systems. These contracts include the following:

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

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

Operations Services Agreement For 34.5 kV Transmission Facilities. ITC Midwest and IP&L entered into the OSA under which IP&L performs certain operations functions for ITC Midwest's 34.5 kV transmission system. The OSA provides that when ITC Midwest upgrades 34.5 kV facilities to higher operating voltages it may notify IP&L of the change and the OSA is no longer applicable to those facilities.

ITC Great Plains

Amended and Restated Maintenance Agreement. Mid-Kansas and ITC Great Plains have entered into the Mid-Kansas Agreement pursuant to which Mid-Kansas has agreed to perform various field operations and maintenance services related to certain ITC Great Plains assets.

ITC Interconnection

ITC Interconnection acquired certain transmission assets from a merchant generating company and placed a 345kV transmission line in service. As a result, ITC Interconnection is a TO in PJM and is subject to rate regulation by the FERC. The revenues earned by ITC Interconnection are based on its facilities reimbursement agreement with the merchant generating company.

Regulatory Environment

Many regulators and public policy makers support the need for further investment in the transmission grid. The growth and changing mix of electricity generation, wholesale power sales and consumption combined with historically inadequate transmission investment have resulted in significant transmission constraints across the United States and increased stress on aging equipment. These problems will continue without increased investment in transmission infrastructure. Transmission system investments can also increase system reliability and reduce the frequency of power outages. Such investments can reduce transmission constraints and improve access to lower cost generation resources, resulting in a lower overall cost of delivered electricity for end-use consumers. The DOE has established the Office of Electricity that focuses on working with reliability experts from the power industry, state governments and their Canadian counterparts to improve grid reliability and increase investment in the country’s electric infrastructure. In addition, the FERC has signaled its desire for substantial new investment in the transmission sector by implementing various financial and other incentives.

The FERC has also issued orders to promote non-discriminatory transmission access for all transmission customers. In the United States, electric transmission assets are predominantly owned, operated and maintained by utilities that also own electricity generation and distribution assets, known as vertically integrated utilities. The FERC has recognized that the vertically-integrated utility model inhibits the provision of non-discriminatory transmission access and, in order to alleviate this potential discrimination, the FERC has mandated that all transmission systems over which it has jurisdiction must be operated in a comparable, non-discriminatory manner such that any seller of electricity affiliated with a TO or transmission operator is not provided with preferential treatment. The FERC has also indicated that independent transmission companies can play a prominent role in furthering its policy goals and has encouraged the legal and functional separation of transmission operations from generation and distribution operations.

The FERC requires TOs to comply with certain reliability standards and may take enforcement actions for violations, including the imposition of substantial fines. NERC is responsible for developing and enforcing these mandatory reliability standards. We continually assess our transmission systems against standards established by NERC, as well as the standards of applicable regional entities under NERC that have been delegated certain authority for the purpose of proposing and enforcing reliability standards.

Finally, utility holding companies are subject to FERC regulations related to access to books and records in addition to the requirement of the FERC to review and approve mergers and consolidations involving utility assets and holding companies in certain circumstances.

Federal Regulation

As electric transmission companies, our Regulated Operating Subsidiaries charge rates that are regulated by the FERC. The FERC is an independent regulatory commission within the DOE that regulates the interstate transmission and certain wholesale sales of natural gas, the transmission of oil and oil products by pipeline and the transmission and wholesale sales of electricity in interstate commerce. The FERC also administers accounting and financial reporting regulations and standards of conduct for the companies it regulates. In order to facilitate open access transmission for participants in wholesale power markets, FERC Order No. 888 encourages investor owned utilities to cede operational control over their transmission systems to ISOs, which are not-for-profit entities.

As an alternative to ceding operating control of their transmission assets to ISOs, certain investor owned utilities began to promote the formation of for-profit transmission companies, which would assume control of the operation of the grid. FERC Order No. 2000 encourages utilities to voluntarily transfer operational control of their transmission systems to RTOs. RTOs, as envisioned in Order No. 2000, would assume many of the functions of an ISO, but the FERC permitted greater flexibility with regard to the organization and structure of RTOs than it had for ISOs. RTOs could accommodate the inclusion of independently owned, for-profit companies that own transmission assets within their operating structure. Independent ownership would facilitate not only the independent operation of the transmission systems, but also the formation of companies with a greater financial interest in maintaining and augmenting the capacity and reliability of those systems. RTOs, such as MISO and SPP, monitor electric reliability and are responsible for coordinating the operation of the wholesale electric transmission system and ensuring fair, non-discriminatory access to the transmission grid.

FERC Order No. 1000 amended certain existing transmission planning and cost allocation requirements to ensure that FERC-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential.

Revenue Requirement Calculations and Cost Sharing for Projects with Regional Benefits

The cost-based Formula Rates used by our Regulated Operating Subsidiaries include revenue requirement calculations for various types of projects. Network revenues continue to be the largest component of revenues recovered through our Formula Rates. However, regional cost sharing revenues have experienced long-term growth as a result of projects that have been identified as having regional benefits and are therefore eligible for regional cost recovery. Separate calculations of revenue requirement are performed for projects that have been approved for regional cost sharing.

We have projects that are eligible for regional cost sharing under the MISO tariff, such as certain network upgrade projects, and the MVPs. Additionally, certain projects at ITC Great Plains are eligible for recovery through a region-wide charge in the SPP tariff, including three regional cost sharing projects in Kansas.

State Regulation

The regulatory agencies in the states where our Regulated Operating Subsidiaries' assets are located do not have jurisdiction over our rates or terms and conditions of service. However, they typically have jurisdiction over siting of transmission facilities and related matters as described below. Additionally, we are subject to the regulatory oversight of various state environmental quality departments for compliance with any state environmental standards and regulations.

ITCTransmission, METC and ITC Interconnection

Michigan

The Michigan Public Service Commission has jurisdiction over the siting of certain transmission facilities. Additionally, ITCTransmission, METC and ITC Interconnection have the right as independent transmission companies to condemn property in the state of Michigan for the purposes of building or maintaining transmission facilities.

ITCTransmission, METC and ITC Interconnection are also subject to the regulatory oversight of the Michigan Department of Environmental Quality, the Michigan Department of Natural Resources and certain local authorities for compliance with all environmental standards and regulations.

ITC Midwest

Iowa

The Iowa Utilities Board has the power of supervision over the construction, operation and maintenance of transmission facilities in Iowa by any entity, which includes the power to issue franchises. Iowa law further provides that any entity granted a franchise by the Iowa Utilities Board is vested with the power of condemnation in Iowa to the extent the Iowa Utilities Board approves and deems necessary for public use. A city has the power, pursuant to Iowa law, to grant a franchise to erect, maintain and operate transmission facilities within the city, which franchise may regulate the conditions required and manner of use of the streets and public grounds of the city and may confer the power to appropriate and condemn private property.

ITC Midwest also is subject to the regulatory oversight of certain state agencies (including the Iowa Department of Natural Resources) and certain local authorities with respect to the issuance of environmental, highway, railroad and similar permits.

Minnesota

The Minnesota Public Utilities Commission has jurisdiction over the construction, siting and routing of new transmission lines or upgrades of existing lines through Minnesota's Certificate of Need and Route Permit Processes. Transmission companies are also required to participate in the state's Biennial Transmission Planning Process and are subject to the state's preventative maintenance requirements. Pursuant to Minnesota law, ITC Midwest has the right as an independent transmission company to condemn property in the state of Minnesota for the purpose of building new transmission facilities.

ITC Midwest is also subject to the regulatory oversight of the Minnesota Pollution Control Agency, the Minnesota Department of Natural Resources, the Minnesota Public Utilities Commission in conjunction with the Department of Commerce and certain local authorities for compliance with applicable environmental standards and regulations.

Illinois

The Illinois Commerce Commission exercises jurisdiction over the siting of new transmission lines through its requirements for Certificates of Public Convenience and Necessity and Right-Of-Way acquisition that apply to construction of new or upgraded facilities.

ITC Midwest is also subject to the regulatory oversight of the Illinois Environmental Protection Agency, the Illinois Department of Natural Resources, the Illinois Pollution Control Board and certain local authorities for compliance with all environmental standards and regulations.

Missouri

Because ITC Midwest is a "public utility" and an "electrical corporation" under Missouri law, the Missouri Public Service Commission has jurisdiction to determine whether ITC Midwest may operate in such capacity. The Missouri Public Service Commission also exercises jurisdiction with regard to other non-rate matters affecting its sole Missouri asset such as transmission substation construction, general safety and the transfer of the franchise or property.

ITC Midwest is also subject to the regulatory oversight of the Missouri Department of Natural Resources for compliance with all environmental standards and regulations relating to this transmission line.

Wisconsin

ITC Midwest is a "public utility" and independent TO in Wisconsin. The Public Service Commission of Wisconsin granted ITC Midwest a certificate of authority to transact public utility business in the state. The Public Service Commission of Wisconsin also recognized ITC Holdings as a public utility holding company under Wisconsin statutes.

The Public Service Commission of Wisconsin exercises jurisdiction over the siting of new transmission lines through the issuance of certificates of authority and certificates of public convenience and necessity. Upon receipt of such certificates for a transmission project, ITC Midwest has condemnation authority as a foreign transmission provider under Wisconsin law. ITC Midwest is also subject to the jurisdiction of certain local and state agencies, including the Wisconsin Department of Natural Resources, relating to environmental and road permits.

ITC Great Plains

Kansas

ITC Great Plains is a "public utility" and an "electric utility" in Kansas pursuant to state statutes. The KCC issued an order approving the issuance of a limited certificate of convenience to ITC Great Plains for the purposes of building, owning and operating SPP transmission projects in Kansas. In addition to its certificate of authority, the KCC has jurisdiction over the siting of electric transmission lines.

ITC Great Plains is also subject to the regulatory oversight of the Kansas Department of Health and Environment for compliance with all environmental standards and regulations relating to the construction phase of any transmission line.

Oklahoma

ITC Great Plains has approval from the Oklahoma Corporation Commission to operate in Oklahoma, pursuant to Oklahoma statutes as an electric public utility providing only transmission services. The Oklahoma Corporation Commission does not exercise jurisdiction over the siting of any transmission lines.

ITC Great Plains is subject to the regulatory oversight of Oklahoma Department of Environmental Quality for compliance with environmental standards and regulations relating to construction of certain proposed transmission lines.

Sources of Revenue

See "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Components of Results of Operations — Revenues" for a discussion of our principal sources of revenue.

Seasonality

The cost-based Formula Rates in effect for our Regulated Operating Subsidiaries, as discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism," mitigate the seasonality of net income for our Regulated Operating Subsidiaries. Our Regulated Operating Subsidiaries accrue or defer revenues to the extent that the actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. For example, to the extent that amounts billed are less than our revenue requirement for a reporting period, a revenue accrual is recorded for the difference and the difference results in no net income impact.

Operating cash flows are seasonal at our MISO Regulated Operating Subsidiaries, in that cash received for revenues is typically higher in the summer months when peak load is higher.

Principal Customers

Our principal transmission service customers are DTE Electric, Consumers Energy and IP&L, which accounted for approximately 21.6%, 23.9% and 23.9%, respectively, of our consolidated billed revenues for the year ended December 31, 2020. One or more of these customers together have consistently represented a significant percentage of our operating revenue. These percentages of total billed revenues of DTE Electric, Consumers Energy and IP&L include the collection of 2018 revenue accruals and deferrals and exclude any amounts for the 2020 revenue accruals and deferrals that were included in our 2020 operating revenues, but will not be billed to our customers until 2022. Refer to “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism” for a discussion on the difference between billed revenues and operating revenues. Our remaining revenues were generated from providing service to other entities such as alternative energy suppliers, power marketers and other wholesale customers that provide electricity to end-use consumers and from transaction-based capacity reservations. Nearly all of our revenues are from transmission customers in the United States. Although we may recognize allocated revenues from time to time from Canadian entities reserving transmission over the Ontario or Manitoba interface, these revenues have not been and are not expected to be material to us.

Billing

MISO and SPP are responsible for billing and collecting the majority of our transmission service revenues as well as independently administering the transmission tariff in their respective service territory. As the billing agents for our MISO Regulated Operating Subsidiaries and ITC Great Plains, MISO and SPP independently bill DTE Electric, Consumers Energy, IP&L and other customers on a monthly basis and collect fees for the use of our transmission systems.

See “Item 7A Quantitative and Qualitative Disclosures about Market Risk — Credit Risk” for discussion of our credit policies.

Competition

Each of our MISO Regulated Operating Subsidiaries operates the primary transmission system in its respective service area and has limited competition for certain projects. However, due to the implementation of the FERC Order No. 1000, other entities with transmission development initiatives may compete with us by seeking approval to be named the party authorized to build new capital projects that we are also pursuing. Our subsidiaries may also compete with other entities on development opportunities for transmission investment in locations outside of our existing service areas. See further discussion of Order No. 1000 above under “Regulatory Environment — Federal Regulation.”

Human Capital Resources

ITC Holdings places significant emphasis on attracting, developing and retaining individuals who exemplify the values that are the cornerstone of our company. As of December 31, 2020, we had 698 employees, with low employee turnover and no significant change in the number of employees from the prior year. None of our employees are covered by collective bargaining agreements. In addition, we work with many outside firms to provide additional resources to support our business. We utilize human capital resources employed by these firms to assist with construction, maintenance, field operations and other corporate functions of our business. We believe that we have good relationships with our suppliers of contracted services.

We believe that our compensation and benefit programs have been appropriately designed to attract and retain talent. Compensation for employees is made up of a combination of base salary, short-term incentive and long-term incentive pay structures. In addition, we offer a comprehensive package of additional benefits for all of our employees and various professional development opportunities through internal and external programs.

Safety is of the utmost importance for our employees, and we consider safety to be a key priority for our company. Our safety policies, procedures and training practices have resulted in safety performance metrics that consistently rank ITC Holdings in the top decile among comparable electric utilities.

We strive to provide an inclusive and diverse environment for all of our employees. We believe that by recognizing and valuing our employees' similarities, as well as their differences, we make our shared goals possible. In addition to our internal commitments to inclusion and diversity, we are also implementing a supplier diversity program. This effort will further diversify our supplier base through the recruitment and growth of businesses owned by minorities, women and veterans.

Environmental Matters

See "Environmental Matters" in Note 18 to the consolidated financial statements.

Available Information Under the Securities Exchange Act of 1934

Our Internet address is http://www.itc-holdings.com. Visit our website to learn more about us. Financial and other material information regarding us is routinely posted on our website and is readily accessible. All of our reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, can be accessed free of charge through our website. These reports are available as soon as practicable after they are electronically filed with the SEC. The information on our website is not incorporated by reference into this report.

ITEM 1A. ***RISK FACTORS.***

Risks Related to Our Business

Certain elements of our Regulated Operating Subsidiaries' Formula Rates have been and can be challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus may have an adverse effect on our business, financial condition, results of operations and cash flows.

Our Regulated Operating Subsidiaries provide transmission service under rates regulated by the FERC. The FERC has approved the cost-based Formula Rates used by our Regulated Operating Subsidiaries to calculate their respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the Formula Rates. All aspects of our Regulated Operating Subsidiaries' rates approved by the FERC, including the Formula Rate templates, the rates of return on the actual equity portion of their respective capital structures, ROE adders for independent transmission ownership, the approved capital structures and other aspects of our rates, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative in a proceeding under Section 206 of the FPA. In addition, interested parties may challenge the annual implementation and calculation by our Regulated Operating Subsidiaries of their projected rates and Formula Rate true up pursuant to their approved Formula Rates under the Regulated Operating Subsidiaries' Formula Rate implementation protocols. End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to our Regulated Operating Subsidiaries, particularly if rates for delivered electricity increase substantially. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC will make adjustments to them and/or disallow any of our Regulated Operating Subsidiaries' inclusion of those aspects in the rate setting formula. This could result in lowered rates and/or refunds of amounts collected, any of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our actual capital investment may be lower than planned, which would cause a lower than anticipated rate base and would therefore result in lower revenues, earnings and associated cash flows compared to our current expectations. In addition, we may incur expenses related to the pursuit of strategic investment opportunities, which may be higher than forecasted.

Each of our Regulated Operating Subsidiaries' rate base, revenues, earnings and associated cash flows are determined in part by additions to property, plant and equipment and when those additions are placed in service. If our operating subsidiaries' capital investment and the resulting in-service property, plant and equipment are lower than anticipated for any reason, our operating subsidiaries will have a lower than anticipated rate base, thus causing their revenue requirements and future earnings and cash flows to be lower than anticipated.

Any capital investment at our Regulated Operating Subsidiaries may be lower than our published estimates due to, among other factors, the impact of:

- actual or forecasted loads;
- regional economic conditions;
- weather conditions;
- union strikes or labor shortages;
- material and equipment prices and availability;
- variances between estimated and actual costs of construction contracts awarded;
- our ability to obtain financing for such expenditures, if necessary;
- limitations on the amount of construction that can be undertaken on our system or transmission systems owned by others at any one time;
- regulatory requirements relating to our rate construct, including our ability to recover costs;
- the potential for greater competition;
- environmental, siting or regional planning issues; and
- legal proceedings.

Our ability to engage in construction projects resulting from pursuing these initiatives is subject to significant uncertainties, including the factors discussed above, and will depend on obtaining any necessary regulatory and other approvals for the project and for us to initiate construction, our achieving status as the builder of the project in some circumstances and other factors. In addition, projects may be canceled, the scope of planned projects may change, or projects may not be completed on time, any of which may adversely affect our level of investment or cause our projected investments to be inaccurate.

In addition, we may incur expenses to pursue strategic investment opportunities. If these payments or expenses are higher than anticipated, our future results of operations, cash flows and financial condition could be materially and adversely affected.

The regulations to which we are subject may limit our ability to raise capital and/or pursue acquisitions, development opportunities or other transactions or may subject us to liabilities.

Each of our Regulated Operating Subsidiaries is a “public utility” under the FPA and, accordingly, is subject to regulation by the FERC. Approval of the FERC is required under Section 203 of the FPA for a disposition or acquisition of regulated public utility facilities, either directly or indirectly through a holding company. Such approval is also required to acquire a significant interest in securities of a public utility. Section 203 of the FPA also provides the FERC with explicit authority over utility holding companies’ purchases or acquisitions of, and mergers or consolidations with, a public utility. Finally, each of our Regulated Operating Subsidiaries must also seek approval by the FERC under Section 204 of the FPA for issuances of its securities (including debt securities). If we are unable to obtain the necessary FERC approvals for potential acquisitions, dispositions or merger activities, or to raise capital, our strategic and growth opportunities may be limited. This could have an adverse impact on our consolidated results of operations, cash flows and financial condition.

We are also pursuing development projects for construction of transmission facilities and interconnections with generating resources. These projects may require regulatory approval by Federal agencies, including the FERC, applicable RTOs and state and local regulatory agencies. Failure to secure such regulatory approval for new strategic development projects could adversely affect our ability to grow our business and increase our revenues. If we fail to obtain these approvals when necessary, we may incur liabilities for such failure.

Changes in energy laws, regulations or policies could impact our business, financial condition, results of operations and cash flows.

Each of our Regulated Operating Subsidiaries is regulated by the FERC as a "public utility" under the FPA and is a TO in MISO, SPP or PJM. We cannot predict whether the approved rate methodologies for any of our Regulated Operating Subsidiaries will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to the FERC, modify provisions of the FPA or provide the FERC or another entity with increased authority to regulate transmission matters. Our Regulated Operating Subsidiaries may be affected by any such changes in federal energy laws, regulations or policies in the future. While our Regulated Operating Subsidiaries are subject to the FERC's exclusive jurisdiction for purposes of rate regulation, changes in state laws affecting other matters, such as transmission siting and construction, could limit investment opportunities available to us.

The widespread outbreak of an illness or other communicable disease, including the COVID-19 pandemic, or any other public health crisis, could have a material adverse impact on our business, results of operations, financial condition, cash flows and credit metrics.

We could be negatively impacted by the widespread outbreak of an illness or any other communicable diseases, or any other public health crisis that results in economic and trade disruptions, including the disruption of global supply chains. COVID-19 is currently impacting the global economy, supply chains and markets. As a result of efforts to limit the spread of COVID-19, such as through various "stay in place" orders issued by states served by our transmission systems, many of the businesses that use our transmission systems, including those with large manufacturing operations, have and may continue to experience operating restrictions or temporarily shut down operations. The impact of efforts to limit the spread of COVID-19 on our business, results of operations and financial condition is uncertain and will ultimately depend on the duration and severity of the pandemic, the length that the various business restrictions are in effect, the impact of recent resurgences of COVID-19 cases and deaths in the United States, and the efficacy and distribution of COVID-19 vaccines.

We cannot predict whether, and the extent to which, COVID-19 will have a material impact on our liquidity, financial condition, and results of operations. We require access to the capital markets to fund capital investments. To the extent that our access to the capital markets is adversely affected by COVID-19, we may need to consider alternative sources of funding for our operations and for working capital, any of which may not be available and may increase our cost of capital. The extent to which COVID-19 may impact our liquidity, financial condition, and results of operations will depend on future developments, which are highly uncertain and cannot be predicted; an extended period of global supply chain and economic disruption could materially impact our business, results of operations, financial condition, cash flows and credit metrics.

Each of our MISO Regulated Operating Subsidiaries depends on its primary customer for a substantial portion of its revenues, and any material failure by those primary customers to make payments for transmission services could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Each of ITCTransmission, METC and ITC Midwest derive a substantial portion of their revenues from the transmission of electricity to the local distribution facilities of DTE Electric, Consumers Energy and IP&L, respectively. Each of these customers is expected to constitute the majority of the revenues of the respective MISO Regulated Operating Subsidiary for the foreseeable future. Any material failure by DTE Electric, Consumers Energy or IP&L to make payments for transmission services could have an adverse effect on our business, financial condition, results of operations and cash flows.

A significant amount of the land on which our assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, we must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact our ability to complete construction projects in a timely manner.

METC does not own the majority of the land on which its electric transmission assets are located. Instead, under the provisions of the Easement Agreement, METC pays an annual rent to Consumers Energy in exchange for rights-of-way, leases, fee interests and licenses which allow METC to use the land on which its transmission lines are located. Under the terms of the Easement Agreement, METC's easement rights could be eliminated if METC fails to meet certain requirements, such as paying contractual rent to Consumers Energy in a timely manner. Additionally, a significant amount of the land on which our other subsidiaries' assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, they must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact their ability to complete their construction projects in a timely manner.

We contract with third parties to provide services for certain aspects of our business. If any of these agreements are terminated, we may face a shortage of labor or replacement contractors to provide the services formerly provided by these third parties.

We enter into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of our business, and we utilize the services of contractors to a significant extent. If any of these agreements or arrangements is terminated for any reason, it could result in a shortage of a readily available workforce to provide such services and we may face difficulty finding a qualified replacement workforce. In such a situation, if we are unable to find adequate replacements for contractors in a timely manner, it could have an adverse effect on our results of operations and the ability to carry on our business.

Hazards associated with high-voltage electricity transmission may result in suspension of our operations, costly litigation or the imposition of civil or criminal penalties.

Our operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. These hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations, litigation by aggrieved parties and the imposition of civil or criminal penalties which may have a material adverse effect on our business, financial condition and results of operations. We maintain property and casualty insurance, but we are not fully insured against all potential hazards incident to our business, such as damage to poles, towers and lines or losses caused by outages.

We are subject to environmental regulations and to laws that can give rise to substantial liabilities from environmental contamination.

We are subject to federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities relating to investigation and remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties we currently own or operate. Such liabilities may arise even where the contamination does not result from noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share.

We have incurred expenses in connection with environmental compliance, and we anticipate that we will continue to do so in the future. Failure to comply with the extensive environmental laws and regulations applicable to us could result in significant civil or criminal penalties and remediation costs. Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Some of our facilities and properties are located near environmentally sensitive areas such as wetlands and habitats of endangered or threatened species. In addition, certain properties in which we operate are, or are suspected of being, affected by environmental contamination. Compliance with these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our costs and, therefore, our business, financial condition and results of operations.

If amounts billed for transmission service for our Regulated Operating Subsidiaries' transmission systems are lower than expected, or our actual revenue requirements are higher than expected, the timing of actual collection of our total revenues would be delayed.

If amounts billed for transmission service are lower than expected, the timing of actual collections of our Regulated Operating Subsidiaries' total revenue requirement would likely be delayed until such circumstances are adjusted through the true-up mechanism, which would be settled within a two-year period, in our Regulated Operating Subsidiaries’ Formula Rates. Lower than expected amounts collected could result from lower network load or point-to-point transmission service on our Regulated Operating Subsidiaries’ transmission systems due to a weak economy, changes in the nature or composition of the transmission assets of our Regulated Operating Subsidiaries and surrounding areas, poor transmission quality of neighboring transmission systems, or for any other reason. In addition, if the revenue requirements of our Regulated Operating Subsidiaries are higher than expected, the timing of actual collection of our Regulated Operating Subsidiaries' total revenue requirements would likely be delayed until such circumstances are reflected through the true-up mechanism, which would be settled within a two-year period, in our Regulated Operating Subsidiaries' Formula Rates. This could be due to higher actual expenditures compared to the forecasted expenditures used to develop their billing rates or for any other reason. The effect of such under-collection would be to reduce the amount of our available cash resources from what we had expected, until such under-collection is corrected through the true-up mechanism in the Formula Rate template, which may require us to increase our outstanding indebtedness, thereby reducing our available borrowing capacity, and may require us to pay interest at a rate that exceeds the interest to which we are entitled in connection with the operation of the true-up mechanism.

We are subject to various regulatory requirements, including reliability standards; contract filing requirements; reporting, recordkeeping and accounting requirements; and transaction approval requirements. Violations of these requirements, whether intentional or unintentional, may result in penalties that, under some circumstances, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The various regulatory requirements to which we are subject include reliability standards established by the NERC, which acts as the nation’s Electric Reliability Organization approved by the FERC in accordance with Section 215 of the FPA. These standards address operation, planning and security of the bulk power system, including requirements with respect to real-time transmission operations, emergency operations, vegetation management, critical infrastructure protection and personnel training. Failure to comply with these requirements can result in monetary penalties as well as non-monetary sanctions. Monetary penalties vary based on an assigned risk factor for each potential violation, the severity of the violation and various other circumstances, such as whether the violation was intentional or concealed, whether there are repeated violations, the degree of the violator’s cooperation in investigating and remediating the violation and the presence of a compliance program, and such penalties can be substantial. Non-monetary sanctions include potential limitations on the violator’s activities or operation and placing the violator on a watchlist for major violators. If any of our subsidiaries violate the NERC reliability standards, even unintentionally, in any material way, any penalties or sanctions imposed against us could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Certain of our subsidiaries are also subject to requirements under Sections 203 and 205 of the FPA for approval of transactions; reporting, recordkeeping and accounting requirements; and for filing contracts related to the provision of jurisdictional services. Under the FERC policy, failure to file jurisdictional agreements on a timely basis may result in foregoing the time value of revenues collected under the agreement, but not to the point where a loss would be incurred. The failure to obtain timely approval of transactions subject to FPA Section 203, or to comply with applicable reporting, recordkeeping or accounting requirements under FPA Section 205, could subject us to penalties that could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may negatively affect our business, financial condition and cash flows in unpredictable ways, such as increased security measures and disruptions of markets. Energy related assets, including, for example, our transmission facilities and DTE Electric’s, Consumers Energy’s and IP&L’s generation and distribution facilities that we interconnect with, may be at risk of acts of war and terrorist attacks, as well as natural disasters, severe weather and other catastrophic events. Such events or threats may have a material effect on the economy in general and could result in a decline in energy consumption, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

A cyber-attack or incident could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Various U.S. Government agencies have noted that external threat sources continue to seek to exploit, through cyber attacks, potential vulnerabilities in the U.S. energy infrastructure including electric transmission assets. These cyber threats and attacks are becoming more sophisticated and dynamic. Cyber security incidents could harm our business by limiting our transmission capabilities, delay our development and construction of new facilities or capital improvement projects on existing facilities or expose us to liability. Cyber attacks targeting our information systems could also impair our records, networks, systems and programs, or transmit viruses to other systems. Such events or the threat of such events may increase costs associated with heightened security requirements. In addition, if our major customers or suppliers experience a cyber attack it may reduce their ability to use our transmission facilities or service our transmission assets. If our business or those of our customers and suppliers are subject to a cyber attack, it may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Changes in tax laws or regulations may negatively affect our results of operations, net income, financial condition, cash flows and credit metrics.

We are subject to taxation by various taxing authorities at the federal, state and local levels. Various representatives of the government, corporations, industry groups and the public continue to pursue changes to tax laws and regulations, and corporate tax reform continues to be a priority in many jurisdictions. Due to unique aspects of the treatment of taxes for regulated utilities, the impacts of changes in tax laws for us and our Regulated Operating Subsidiaries may differ from the impacts to other corporations generally. Changes in federal, state or local tax rates or other aspects of tax laws could materially and adversely affect our results of operations, net income, financial condition, cash flows, and credit metrics.

Advances in technology may negatively impact our business, financial condition, results of operations and cash flows.

Research and development efforts continue to seek improvements to existing or new alternative technologies to produce, store and distribute power, including fuel cells, microturbines, distributed generation and battery storage. It is possible that adoption of such alternative technologies could be significant enough to cause a reduction in the demand for electricity from the traditional bulk electric system or could make portions of our transmission systems obsolete before the end of their useful lives. Such advances in alternative technologies could decrease the need for capital investments in our transmission systems over time or increase cost, and as a result could have an adverse effect on our business, financial condition, results of operations and cash flows.

Risks Relating to Our Corporate and Financial Structure

ITC Holdings is a holding company with no operations, and unless we receive dividends or other payments from our subsidiaries, we may be unable to fulfill our cash obligations.

As a holding company with no business operations, ITC Holdings’ material assets consist primarily of the stock and membership interests in our subsidiaries. Our only sources of cash to meet our obligations are dividends and other payments received by us from time to time from our subsidiaries, the proceeds raised from the sale of our securities and borrowings under our various credit agreements. Each of our subsidiaries, however, is legally distinct from us and has no obligation, contingent or otherwise, to make funds available to us. The ability of each of our Regulated Operating Subsidiaries and our other subsidiaries to pay dividends and make other payments to us is subject to, among other things, the availability of funds, after taking into account capital expenditure requirements, the terms of its indebtedness, applicable state laws and regulations of the FERC and the FPA. Our Regulated Operating Subsidiaries target a FERC-approved capital structure of 60% equity and 40% debt that may limit the ability of our Regulated Operating Subsidiaries to use net assets for the payment of dividends to ITC Holdings. In addition, ITC Holdings’ right to receive any assets of any subsidiary, and therefore the right of its creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary’s creditors. If ITC Holdings does not receive cash or other assets from our subsidiaries, it may be unable to pay principal and interest on its indebtedness.

We have a considerable amount of debt and our reliance on debt financing may limit our ability to fulfill our debt obligations and/or to obtain additional financing.

We have a considerable amount of debt and our consolidated indebtedness includes various debt securities and borrowings, which utilize indentures, revolving and term loan credit agreements and commercial paper that we rely on as sources of capital and liquidity. Our capital structure can have several important consequences, including, but not limited to, the following:

- If future cash flows are insufficient, we may not be able to make principal or interest payments on our debt obligations, which could result in the occurrence of an event of default under one or more of those debt instruments.
- We may need to increase our indebtedness in order to make the capital expenditures and other expenses or investments planned by us.
- Our indebtedness has the general effect of reducing our flexibility to react to changing business and economic conditions insofar as they affect our financial condition. A substantial portion of the dividends and payments in lieu of taxes we receive from our subsidiaries will be dedicated to the payment of interest on our indebtedness, thereby, reducing our available cash.
- In the event that we are liquidated, the creditors of our subsidiaries will be entitled to payment in full of the subsidiaries' indebtedness prior to making any payments to ITC Holdings for the payment of its indebtedness.
- We currently have debt instruments outstanding with short-term maturities or relatively short remaining maturities. Our ability to secure additional financing prior to or after these facilities mature, if needed, may be substantially restricted by the existing level of our indebtedness and the restrictions contained in our debt instruments. Additionally, the interest rates at which we might secure additional financings may be higher than our currently outstanding debt instruments or higher than forecasted at any point in time, which could adversely affect our business, financial condition, results of operations and cash flows.
- Market conditions could affect our access to capital markets, restrict our ability to secure financing to make the capital expenditures and investments and pay other expenses planned by us which could adversely affect our business, financial condition, cash flows and results of operations.

We may incur substantial additional indebtedness in the future. The incurrence of additional indebtedness would increase the leverage-related risks described above.

Adverse changes in our credit ratings may negatively affect us.

Our ability to access capital markets is important to our ability to operate our business. Increased scrutiny of the energy industry and the impact of regulation, as well as changes in our financial performance and unfavorable conditions in the capital markets could result in credit agencies reexamining and downgrading our credit ratings. In addition, because we are a subsidiary of Fortis, a downgrade in Fortis' credit rating could cause our credit rating to be downgraded as well, even if our creditworthiness has not otherwise deteriorated. A downgrade in our credit ratings could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs. A rating downgrade could also increase the interest we pay on commercial paper and under our revolving and term loan credit agreements.

Certain provisions in our debt instruments limit our financial and operating flexibility.

Our debt instruments on a consolidated basis, including senior notes, secured notes, first mortgage bonds, revolving and term loan credit agreements and commercial paper, contain numerous financial and operating covenants that place significant restrictions on, among other things, our ability to:

- incur additional indebtedness;
- engage in sale and lease-back transactions;
- create liens or other encumbrances;
- enter into mergers, consolidations, liquidations or dissolutions, or sell or otherwise dispose of all or substantially all of our assets;

- create and acquire subsidiaries; and
- pay dividends or make distributions on our stock or on the stock or member capital of our subsidiaries.

In addition, the covenants require us to meet certain financial ratios, such as maintaining certain debt to capitalization ratios and certain funds from operations to debt levels. Our ability to comply with these and other requirements and restrictions may be affected by changes in economic or business conditions, results of operations or other events beyond our control. A failure to comply with the obligations contained in any of our debt instruments could result in acceleration of related debt and the acceleration of debt under other instruments evidencing indebtedness that may contain cross-acceleration or cross-default provisions.

ITEM 1B. *UNRESOLVED STAFF COMMENTS.*

None.

ITEM 2. *PROPERTIES.*

Our Regulated Operating Subsidiaries' transmission facilities are located in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma. Our MISO Regulated Operating Subsidiaries and ITC Great Plains have agreements with other utilities for the joint ownership of specific substations, transmission lines and other transmission assets. See Note 16 to the consolidated financial statements for more information on the jointly owned assets.

Our Regulated Operating Subsidiaries own the assets of transmission systems and related assets, including:

- approximately 16,000 circuit miles of overhead and underground transmission lines rated at voltages of 34.5 kV to 345 kV, along with related transmission towers and poles;
- station assets, such as transformers and circuit breakers, at approximately 673 stations and substations which either interconnect our Regulated Operating Subsidiaries' transmission facilities or connect our Regulated Operating Subsidiaries' facilities with generation or distribution facilities owned by others;
- other transmission equipment necessary to safely operate the system (e.g., monitoring and metering equipment);
- warehouses and related equipment; and
- associated land held in fee, rights-of-way and easements.

ITCTransmission owns a corporate headquarters facility and operations control room in Novi, Michigan and a facility in Ann Arbor, Michigan that includes a back-up operations control room, along with associated furniture, fixtures and office equipment for these facilities.

METC does not own the majority of the land on which its assets are located, but under the provisions of the Easement Agreement, METC has an easement to use the land, rights-of-way, leases and licenses in the land on which its transmission lines are located that are held or controlled by Consumers Energy. See "Item 1 Business - Operating Contracts - METC - Amended and Restated Easement Agreement."

Certain of our Regulated Operating Subsidiaries have issued First Mortgage Bonds and Senior Secured Notes. Under the terms of these instruments, the respective bondholders and noteholders have the benefit of a first mortgage lien on substantially all of the assets of the corresponding debt issuer. Refer to Note 10 to the consolidated financial statements for more information on the outstanding debt of our Regulated Operating Subsidiaries. As of December 31, 2020, there were no liens or encumbrances on the assets of ITC Interconnection.

The assets of our Regulated Operating Subsidiaries are suitable for electric transmission and adequate for the electricity demand in our service territory. We prioritize capital spending based in part on meeting reliability standards within the industry. This includes replacing and upgrading existing assets as needed.

ITEM 3. *LEGAL PROCEEDINGS.*

We are involved in certain legal proceedings before various courts, governmental agencies and mediation panels concerning matters arising in the ordinary course of business. These proceedings include certain contract disputes, regulatory matters and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss.

Refer to Notes 6 and 18 to the consolidated financial statements for a description of certain pending legal proceedings, which description is incorporated herein by reference.

ITEM 4. *MINE SAFETY DISCLOSURES.*

Not applicable.

PART II

ITEM 5. *MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.*

ITC Holdings is a wholly-owned subsidiary of ITC Investment Holdings and ITC Holdings' common stock is not publicly traded.

ITC Holdings paid dividends of $330 million and $250 million to our parent, ITC Investment Holdings, during the years ended December 31, 2020 and 2019, respectively. ITC Holdings also paid dividends of $58 million to ITC Investment Holdings in January 2021. The timing and amount of future dividends is subject to an approved dividend declaration from our Board of Directors, and is dependent upon cash flows, capital requirements, legislative and regulatory developments, and financial condition of ITC Holdings, among other factors deemed relevant.

ITEM 6. *SELECTED FINANCIAL DATA.*

Information required by Item 6 of Form 10-K is omitted pursuant to the SEC's adoption of amendments to Regulation S-K effective February 10, 2021.

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.*

Safe Harbor Statement Under The Private Securities Litigation Reform Act of 1995

Our reports, filings and other public announcements contain certain statements that describe our management's beliefs concerning future business conditions, plans and prospects, growth opportunities, the outlook for our business and the electric transmission industry, and expectations with respect to various legal and regulatory proceedings based upon information currently available. Such statements are "forward-looking" statements within the meaning of the Private Securities Litigation Reform Act of 1995. Wherever possible, we have identified these forward-looking statements by words such as "will," "may," "anticipates," "believes," "intends," "estimates," "expects," "forecasted," "projects," "likely" and similar phrases. These forward-looking statements are based upon assumptions our management believes are reasonable. Such forward-looking statements are based on estimates and assumptions and subject to significant risks and uncertainties which could cause our actual results, performance and achievements to differ materially from those expressed in, or implied by, these statements, including, among others, the risks and uncertainties listed in this report under "Item 1A Risk Factors" and in our other reports filed with the SEC from time to time.

Forward-looking statements speak only as of the date made and can be affected by assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this report will be important in determining future results. Consequently, we cannot assure you that our expectations or forecasts expressed in such forward-looking statements will be achieved. Except as required by law, we undertake no obligation to publicly update any of our forward-looking or other statements, whether as a result of new information, future events or otherwise.

Statement on Prior Period Comparisons

This section of this Form 10-K generally discusses the financial condition, changes in financial condition and results of operations for the years ended December 31, 2020 and 2019 and provides year-to-year comparisons between the years ended December 31, 2020 and 2019. Discussions of such information for the year ended December 31, 2018 and year-to-year comparisons between the years ended December 31, 2019 and 2018 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial

Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

Overview

ITC Holdings and its subsidiaries are engaged in the transmission of electricity in the United States. ITC Holdings is a wholly-owned subsidiary of ITC Investment Holdings. Through our Regulated Operating Subsidiaries, we own and operate high-voltage electric transmission systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to our transmission systems.

ITC Holdings provides safe and reliable electric transmission service to connect consumers to cleaner and more cost-effective energy resources. ITC Holdings is leading the way in making investments in a modernized grid to maintain reliability and accommodate future demands as our economy and lifestyles become increasingly dependent on electricity. We are actively involved in planning an integrated energy network to serve our customers, communities and the greater grid.

Our business strategy is focused on owning, operating, maintaining and investing in transmission infrastructure and grid solutions in order to enhance system reliability, protect critical infrastructure, reduce transmission constraints, interconnect new renewable generation resources, expand access to electricity markets and lower the overall cost of delivered energy.

Our Regulated Operating Subsidiaries earn revenues for the use of their electric transmission systems by their customers, which include investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, our Regulated Operating Subsidiaries are subject to rate regulation only by the FERC, and our cost-based rates are discussed below under "— Cost-Based Formula Rates with True-Up Mechanism" as well as in Note 6 to the consolidated financial statements.

Our Regulated Operating Subsidiaries' primary operating responsibilities include maintaining, improving and expanding their transmission systems to meet their customers' ongoing needs, scheduling outages on system elements to allow for maintenance and construction, maintaining appropriate system voltages and monitoring flows over transmission lines and other facilities to ensure physical limits are not exceeded.

Significant recent matters that influenced our financial condition, results of operations and cash flows for the year ended December 31, 2020 or that may affect future results include:

- The outbreak of the COVID-19 pandemic that led to efforts to control the spread of the virus, which have resulted in impacts to businesses and facilities in various industries around the world, such as operating restrictions and closures, and disruptions to the global economy and supply chains;
- Our capital expenditures of $885 million at our Regulated Operating Subsidiaries during the year ended December 31, 2020, as described below under "— Capital Investment and Operating Results Trends" resulted primarily from our focus on improving system reliability, increasing system capacity and upgrading the transmission network to support new generating resources, which included electric transmission asset acquisitions from Consumers Energy of $58 million, of which $29 million was an acquisition premium that was excluded from rate base;
- Debt issuances, other borrowings and repayments as described in Note 10 to the consolidated financial statements to fund capital investment at our Regulated Operating Subsidiaries as well as for general corporate purposes;
- Issuance of the May 2020 Order related to the MISO ROE Complaints, as described in Note 18 to the consolidated financial statements, which reaffirmed the decision in the November 2019 Order to dismiss the Second Complaint and the revised methodology outlined in the November 2019 Order for determining the base ROE for the period of the Initial Complaint and the period subsequent to the September 2016 Order; and
- Issuance of a NOPR by the FERC on March 20, 2020 that included a proposal to update the transmission incentives policy, among other things, to grant incentives to transmission projects based upon benefits to customers ensuring reliability and reducing the cost of delivered power by reducing transmission

congestion, to eliminate the ROE adder for independent transmission ownership, and to increase the ROE adder for RTO participation.

These items are discussed in more detail throughout “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Cost-Based Formula Rates with True-Up Mechanism

Our Regulated Operating Subsidiaries calculate their revenue requirements using cost-based Formula Rates that are effective without the need to file rate cases with the FERC, although the rates are subject to legal challenge at the FERC. Under their cost-based formula, each of our Regulated Operating Subsidiaries separately calculates a revenue requirement based on financial information specific to each company. The calculation of projected revenue requirement for a future period is used to establish the transmission rate used for billing purposes. The calculation of actual revenue requirements for a historic period is used to calculate the amount of revenues recognized in that period and determine the over- or under-collection for that period.

Under these Formula Rates, our Regulated Operating Subsidiaries recover expenses and earn an authorized return on and recover investments in property, plant and equipment on a current basis. The Formula Rates for a given year reflect forecasted expenses, property, plant and equipment, point-to-point revenues, network load at our MISO Regulated Operating Subsidiaries and other items for the upcoming calendar year to establish projected revenue requirements for each of our Regulated Operating Subsidiaries that are used as the basis for billing for service on their systems from January 1 to December 31 of that year. Our Formula Rates include a true-up mechanism, whereby our Regulated Operating Subsidiaries compare their actual revenue requirements to their billed revenues for each year to determine any over- or under-collection of revenue. The over- or under-collection typically results from differences between the projected revenue requirement used as the basis for billing and actual revenue requirement at each of our Regulated Operating Subsidiaries, or from differences between actual and projected monthly network peak loads at our MISO Regulated Operating Subsidiaries. In the event billed revenues in a given year are more or less than actual revenue requirements, which are calculated primarily using information from that year’s FERC Form No. 1, our Regulated Operating Subsidiaries will refund or collect additional revenues, with interest, within a two-year period such that customers pay only the amounts that correspond to actual revenue requirements for that given period. This annual true-up ensures that our Regulated Operating Subsidiaries recover their allowed costs and earn their authorized returns.

See “Cost-Based Formula Rates with True-Up Mechanism” in Note 6 to the consolidated financial statements for further discussion of our Formula Rates and see “Rate of Return on Equity Complaints” in Note 18 to the consolidated financial statements for detail on ROE matters.

Illustrative Example of Formula Rate Setting

The Formula Rate setting example shown below is for illustrative purposes only and is not based on our actual financial data.

Line	Item	Instructions	Amount
1	Rate base (a)		$ 1,000,000
2	Multiply by 13-month weighted average cost of capital (b)		8.46 %
3	Authorized return on rate base	(Line 1 x Line 2)	$ 84,600
4	Recoverable operating expenses (including depreciation and amortization)		$ 150,000
5	Income taxes (c)		37,500
6	Gross revenue requirement	(Line 3 + Line 4 + Line 5)	$ 272,100

(a) Consists primarily of in-service property, plant and equipment, net of accumulated depreciation.

(b) The weighted average cost of capital for purposes of this illustration is calculated below. The cost of capital for debt is included at a flat interest rate for purposes of this illustration and is not based on our actual cost of capital. The cost of capital rate for equity represents the current maximum allowed MISO ROE per the May 2020 Order on the Initial Complaint. See Note 18 to the consolidated financial statements for detail on ROE matters.

	Percentage of Total Capitalization	Cost of Capital	Weighted Average Cost of Capital
Debt	40.00%	5.00% =	2.00 %
Equity	60.00%	10.77% =	6.46 %
	100.00%		8.46 %

(c) Represents an approximation of the federal and state income tax expense for purposes of this illustration and is not based on our actual tax expense.

Revenue Accruals and Deferrals — Effects of Monthly Peak Loads

For our MISO Regulated Operating Subsidiaries, monthly network peak loads are used for billing network revenues, which currently is the largest component of our operating revenues. One of the primary factors that impacts the revenue accruals and deferrals at our MISO Regulated Operating Subsidiaries is actual monthly network peak loads experienced as compared to those forecasted in establishing the annual network transmission rate. Under their cost-based Formula Rates that contain a true-up mechanism, our MISO Regulated Operating Subsidiaries accrue or defer revenues to the extent that their actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. Although monthly network peak loads do not impact operating revenues recognized, network load affects the timing of our cash flows from transmission service. The monthly network peak load of our MISO Regulated Operating Subsidiaries is generally impacted by weather and economic conditions and seasonally shaped with higher load in the summer months when cooling demand is higher.

ITC Great Plains does not receive revenue based on a peak load or a dollar amount per kW each month. Therefore, peak load does not have a seasonal effect on operating cash flows. The SPP tariff applicable to ITC Great Plains is billed ratably each month based on its annual projected revenue requirement posted annually by SPP.

Capital Investment and Operating Results Trends

We expect a long-term upward trend in rate base resulting from our anticipated capital investment, in excess of depreciation and any acquisition premiums, from our Regulated Operating Subsidiaries' long-term capital investment programs to improve reliability, increase system capacity and upgrade the transmission network to support new generating resources. Investments in property, plant and equipment, when placed in-service upon completion of a capital project, are added to the rate base of our Regulated Operating Subsidiaries. While we expect increases in rate base to result in a corresponding long-term upward trend in revenues and earnings, our revenues and earnings are also impacted by changes in our ROE or required refunds resulting from the resolution of the incentive adders complaints and MISO ROE Complaints, as described in Note 6 and Note 18 to the consolidated financial statements, or other future increases or decreases to our rates for incentive adders and base ROE.

Our Regulated Operating Subsidiaries strive for high reliability of their systems and improvement in system accessibility for all generation resources. The FERC requires compliance with certain reliability standards and may take enforcement actions against violators, including the imposition of substantial fines. NERC is responsible for developing and enforcing these mandatory reliability standards. We continually assess our transmission systems against standards established by NERC, as well as the standards of applicable regional entities under NERC that have been delegated certain authority for the purpose of proposing and enforcing reliability standards. We believe that we meet the applicable standards in all material respects, although further investment in our transmission systems and an increase in maintenance activities will likely be needed to maintain compliance, improve reliability and address any new standards that may be promulgated.

We also assess our transmission systems against our own planning criteria that are filed annually with the FERC. Based on our planning studies, we see needs to make capital investments to: (1) maintain and replace our current transmission infrastructure including enhancing system integrity and reliability and accommodating load growth; (2) upgrade physical and technological grid security; (3) promote the transformation of the generation fleet to cleaner and more sustainable resources through required interconnections and transmission build-out; and (4) develop and build regional transmission infrastructure. We do not currently expect any material decrease in planned capital expenditures due to COVID-19; however, we continue to evaluate potential impacts of COVID-19 on our forecasted capital expenditures. Depending on the length and severity of future impacts of COVID-19, certain planned capital expenditures may be shifted to later years of the forecast. The following table shows our actual and expected capital expenditures at our Regulated Operating Subsidiaries:

(In millions of USD)	**Actual Capital Expenditures for the year ended December 31, 2020**	**Forecasted Capital Expenditures 2021 — 2025**
Expenditures for property, plant and equipment (a)	$ 885	$ 3,864

(a) Amounts represent the cash payments to acquire or construct property, plant and equipment, as presented in the consolidated statements of cash flows. These amounts exclude non-cash additions to property, plant and equipment for the AFUDC equity as well as accrued liabilities for construction, labor and materials that have not yet been paid.

Our long-term growth plan includes ongoing investments in our current regulated transmission systems and the identification of incremental strategic projects primarily located in and around our service territories. Refer to “Item 1 Business — Development of Business” for additional information.

Investments in property, plant and equipment could be lower than expected due to a variety of factors, as discussed in “Item 1A Risk Factors”. In addition, investments in transmission network upgrades for generator interconnection projects could change from prior estimates significantly due to changes in the MISO queue for generation projects and other factors beyond our control.

Recent Developments

COVID-19 Pandemic

In March 2020, the World Health Organization declared COVID-19 a pandemic. Efforts to control the outbreak of COVID-19 have resulted in impacts to businesses and facilities in various industries around the world, such as operating restrictions and closures, and disruptions to the global economy and supply chains. The COVID-19 pandemic has and will continue to impact our customers throughout our operating footprint. To date, COVID-19 has not had a material impact on our net income. However, we have implemented various temporary cost saving measures related to operating expenses, including operation and maintenance expenses and general and administrative expenses, in an attempt to reduce costs that are collected from customers through our Formula Rates.

The total impact on our operations from COVID-19 is unknown at this time and will ultimately depend on the duration and severity of the pandemic, the length that the various business restrictions are in effect, the impact of recent resurgences of COVID-19 cases and deaths in the United States, and the efficacy and distribution of COVID-19 vaccines. We are continuing to monitor developments involving our workforce, customers and suppliers and cannot predict whether COVID-19 will have a material impact on our consolidated results of operations, cash flows or financial condition. We are also monitoring the evolving situation and guidance from federal, state and local public health authorities. We are taking steps to mitigate the potential risks to us and our employees posed by COVID-19, including enabling remote work arrangements for employees when appropriate, and are following all government requirements to reduce the transmission of COVID-19.

Monthly Network Peak Load

For our MISO Regulated Operating Subsidiaries, monthly network peak loads are used for billing network revenues, which currently is the largest component of our operating revenues. One of the primary factors that impacts our collection of revenues is actual monthly network peak load, which is impacted by a number of factors including network usage and weather. Although monthly network peak loads do not impact our recognition of operating revenues, actual network load affects the timing of collection of our cash flows from transmission service. During 2020, actual monthly network peak load for our MISO Regulated Operating Subsidiaries decreased compared to pre-COVID-19 forecasted load. This decrease was primarily as a result of reductions in, or suspension of, operations for many businesses and facilities in our operating footprint due to COVID-19. While the decrease in monthly network peak load was significant in the early months of the pandemic, the impact of COVID-19 on monthly network peak loads became less pronounced over the second half of the year. We are unable to predict the possible future impacts of COVID-19, weather and other factors on monthly network peak loads at our MISO Regulated Operating Subsidiaries.

Liquidity and Access to Capital Markets

The COVID-19 pandemic has caused a disruption in capital markets and has resulted in periods of limited access to certain types of funding in the United States, including borrowings on commercial paper programs. We rely on both internal and external sources of liquidity to provide working capital and fund capital investments. During 2020, we were able to successfully access the capital markets to satisfy our liquidity needs. However, if further disruption to the capital markets occurs due to the COVID-19 pandemic, we may have limited access to capital markets and encounter increased borrowing costs.

Rate of Return on Equity Complaints

Two complaints were filed with the FERC by combinations of consumer advocates, consumer groups, municipal parties and other parties challenging the base ROE in MISO. In addition to the MISO ROE Complaints, complaints were filed with the FERC regarding the regional base ROE rate for ISO New England TOs. See Note 18 to the consolidated financial statements for a summary of the MISO ROE Complaints and related proceedings.

Related FERC Orders

In April 2017, the D.C. Circuit Court vacated certain precedent-setting FERC orders that established and applied the two-step DCF methodology for the determination of base ROE for ISO New England TOs. The court remanded the orders to the FERC for further justification of its establishment of the new base ROE for the ISO New England TOs. The vacated orders in the ISO New England matters also provided the precedent for the September 2016 Order on the Initial Complaint and the ALJ initial decision on the Second Complaint for our MISO Regulated Operating Subsidiaries. On October 16, 2018, in the New England matters, the FERC issued an order on remand which proposed a new methodology for 1) determining when an existing ROE is no longer just and reasonable; and 2) setting a new just and reasonable ROE if an existing ROE has been found not to be just and reasonable.

The FERC issued a similar order, the November 2018 Order, in the MISO ROE Complaints, establishing a paper hearing on the application of the proposed new methodology to the proceedings pending before the FERC involving the ROE of the MISO TOs, including our MISO Regulated Operating Subsidiaries. The November 2018 Order included illustrative, non-binding calculations for the ROE that could have been established for the Initial Complaint using the FERC's proposed methodology. The November 2018 Order and our response to the order through briefs and reply briefs did not provide a reasonable basis for a change to the reserve or ROEs utilized for any of the complaint refund periods nor all subsequent periods.

November 2019 Order

On November 21, 2019, the FERC issued an order on the MISO ROE Complaints. The FERC did not adopt the methodology proposed in the November 2018 Order, but rather applied a methodology to the Initial Complaint period that used two financial models to determine the base ROE. The FERC determined that the base ROE for the Initial Complaint should be 9.88% and the top of the range of reasonableness for that period should be 12.24% and that this base ROE should apply during the first refund period of November 12, 2013 to February 11, 2015 and from the date of the September 2016 Order prospectively. In the November 2019 Order, the FERC also dismissed the Second Complaint. Therefore, based on the November 2019 Order, for the Second Complaint refund period from February 12, 2015 to May 11, 2016, no refund is due. As a result, we reversed the aggregate estimated current liability we had previously recorded for the Second Complaint, as noted below in “Financial Statement Impacts”. In addition, for the period from May 12, 2016 to September 27, 2016, no refund is due because no complaint had been filed for that period. The FERC ordered refunds to be made in accordance with the November 2019 Order and, on December 18, 2019, the FERC granted an extension until December 23, 2020 for settlement of the refunds. The MISO TOs, including our MISO Regulated Operating Subsidiaries, and several other parties filed requests for rehearing of the November 2019 Order. The MISO TOs filed their request for rehearing primarily on the basis that the methodology applied by the FERC in the November 2019 Order does not allow the MISO TOs to earn a reasonable rate of return on their investment, as required by precedent. On January 21, 2020, the FERC issued an order granting rehearing for further consideration.

May 2020 Order

On May 21, 2020, the FERC issued an order on rehearing of the November 2019 Order. In this order, the FERC revised its November 2019 Order methodology, finding that three financial models should be used to determine the base ROE, among other revisions. By applying the new methodology, FERC determined that the base ROE for the Initial Complaint should be 10.02% and the top of the range of reasonableness for that period should be 12.62%. The FERC determined that this base ROE should apply during the first refund period of November 12, 2013 to February 11, 2015 and from the date of the September 2016 Order prospectively. The FERC ordered refunds to be made in accordance with the May 2020 Order by December 23, 2020, and on October 8, 2020, the FERC granted an extension to September 23, 2021. In the May 2020 Order, the FERC also reaffirmed its decision to dismiss the Second Complaint and its finding that no refunds would be ordered on the Second Complaint. Our MISO Regulated Operating Subsidiaries are parties to multiple appeals of the September 2016 Order, November 2019 Order and May 2020 Order at the D.C. Circuit Court.

Financial Statement Impacts

As of December 31, 2020, we had recorded an aggregate current regulatory asset and current regulatory liability of $8 million and $13 million, respectively, and as of December 31, 2019, we had recorded an aggregate current regulatory liability of $70 million in the consolidated statements of financial position. These impacts reflect amounts owed from or due to customers under the terms outlined in the May 2020 Order and the November 2019 Order on the Initial Complaint and the periods subsequent to the September 2016 Order. During the year ended December 31, 2020, we refunded $31 million of the regulatory liability to customers. We had recorded an aggregate estimated current regulatory liability in the consolidated statements of financial position of $151 million as of December 31, 2018 for the Second Complaint, which was reversed in November 2019 following the November 2019 Order. Although the November 2019 Order and May 2020 Order dismissed the Second Complaint with no refunds required, it is possible upon appeal that our MISO Regulated Operating Subsidiaries will be required to provide refunds related to the Second Complaint and these refunds could be material.

Our MISO Regulated Operating Subsidiaries currently record revenues at the base ROE of 10.02% established in the May 2020 Order plus applicable incentive adders. See Note 6 to the consolidated financial statements for a summary of incentive adders for transmission rates.

The recognition of the obligations associated with the MISO ROE Complaints resulted in the following impacts to the consolidated statements of comprehensive income:

	Year Ended December 31,		
(In millions of USD)	2020	2019	2018
Revenue increase	$ 32	$ 69	$ 1
Interest expense (decrease) increase	(3)	(12)	7
Estimated net income increase (decrease)	25	61	(4)

As of December 31, 2020, our MISO Regulated Operating Subsidiaries had a total of approximately $5 billion of equity in their collective capital structures for ratemaking purposes. Based on this level of aggregate equity, we estimate that each 10 basis point change in the authorized ROE would impact annual consolidated net income by approximately $5 million.

Challenges to Incentive Adders for Transmission Rates

On March 20, 2020, the FERC issued a NOPR including a proposal to update the transmission incentives policy to grant incentives to transmission projects based upon benefits to customers. The outcome of this proposal may impact the incentive adders that our Regulated Operating Subsidiaries are authorized to apply to their base ROEs on a prospective basis. See Note 6 to the consolidated financial statements for a summary of incentive adders for transmission rates.

MISO Regulated Operating Subsidiaries

On April 20, 2018, Consumers Energy, IP&L, Midwest Municipal Transmission Group, Missouri River Energy Services, Southern Minnesota Municipal Power Agency and WPPI Energy filed a complaint with the FERC under section 206 of the FPA, challenging the adders for independent transmission ownership that are included in transmission rates charged by the MISO Regulated Operating Subsidiaries. The adders for independent transmission ownership allowed up to 50 basis points or 100 basis points to be added to the MISO Regulated Operating Subsidiaries' authorized ROE, subject to any ROE cap established by the FERC. On October 18, 2018, the FERC issued an order granting the complaint in part, setting revised adders for independent transmission ownership for each of the MISO Regulated Operating Subsidiaries to 25 basis points, and requiring the MISO Regulated Operating Subsidiaries to include the revised adders, effective April 20, 2018, in their Formula Rates. In addition, the order directed the MISO Regulated Operating Subsidiaries to provide refunds, with interest, for the period from April 20, 2018 through October 18, 2018. The MISO Regulated Operating Subsidiaries began reflecting the 25 basis point adder for independent transmission ownership in transmission rates in November 2018. Refunds of $7 million were primarily made in the fourth quarter of 2018 and were completed in the first quarter of 2019. The MISO Regulated Operating Subsidiaries sought rehearing of the FERC's October 18, 2018 order, and on July 18, 2019, the FERC denied the rehearing request. On September 11, 2019, the MISO Regulated Operating Subsidiaries filed an appeal of the FERC's order in the D.C. Circuit Court. On December 16, 2019, the D.C. Circuit Court established a briefing schedule for the appeal. An initial brief was filed on January 27, 2020 and a reply brief was filed on April 24, 2020. Oral argument on the appeal was held on September 23, 2020. We do not expect the final resolution of this proceeding to have a material adverse impact on our consolidated results of operations, cash flows or financial condition.

ITC Great Plains

On June 11, 2019, KCC filed a complaint with the FERC under section 206 of the FPA, challenging the ROE adder for independent transmission ownership that is included in the transmission rate charged by ITC Great Plains. The complaint argues that because ITC Great Plains is similarly situated to our MISO Regulated Operating Subsidiaries with respect to ownership by Fortis and GIC, the same rationale by which the FERC lowered the MISO Regulated Operating Subsidiaries adders for independent transmission ownership, as discussed above, also applies to ITC Great Plains. The adder for independent transmission ownership allowed up to 100 basis points to be added to the ITC Great Plains authorized ROE, subject to any ROE cap established by the FERC. ITC Great Plains filed an answer to the complaint on July 1, 2019 asking the FERC to deny the complaint since KCC showed no evidence that ITC Great Plains' independence or the benefits they provide as an independent TO has been compromised or reduced as a result of the Fortis and GIC acquisition. On July 16, 2020, the FERC issued an order granting the complaint, setting the revised adder for independent transmission ownership for ITC Great Plains to 25 basis points, and requiring ITC Great Plains to include the revised adder, effective June 11, 2019, in their Formula Rates. In addition, the order directed ITC Great Plains to provide refunds, with interest, for the period from June 11, 2019 through July 16, 2020 within 60 days of the date of the order. On September 15, 2020, the FERC granted an extension to issue refunds until November 19, 2020. On August 17, 2020, ITC Great Plains filed a request for rehearing of the order and on September 17, 2020, the FERC denied the rehearing request. On November 12, 2020, ITC Great Plains filed an appeal of the July 16, 2020 order, and on December 14, 2020, ITC Great Plains filed an appeal of the September 17, 2020 order, both of which were filed in the D.C. Circuit Court. As of December 31, 2019, we had recorded an estimated current regulatory liability of $2 million related to this complaint and during 2020 refunds of $4 million were made to settle the refund liability. We do not expect the final resolution of this proceeding to have a material adverse impact on our consolidated results of operations, cash flows or financial condition.

Significant Components of Results of Operations

Revenues

We derive nearly all of our revenues from providing transmission, scheduling, control and dispatch services and other related services over our Regulated Operating Subsidiaries’ transmission systems to DTE Electric, Consumers Energy, IP&L and other entities, such as alternative energy suppliers, power marketers and other wholesale customers that provide electricity to end-use consumers, as well as from transaction-based capacity reservations on our transmission systems. MISO and SPP are responsible for billing and collecting the majority of transmission service revenues. As the billing agents for our MISO Regulated Operating Subsidiaries and ITC Great Plains, MISO and SPP collect fees for the use of our transmission systems, invoicing DTE Electric, Consumers Energy, IP&L and other customers on a monthly basis.

Network Revenues are generated from network customers for their use of our electric transmission systems and are based on the actual revenue requirements as a result of our accounting under our cost-based Formula Rates that contain a true-up mechanism. Refer below under “— Critical Accounting Policies and Estimates — Revenue Recognition under Cost-Based Formula Rates with True-Up Mechanism” for a discussion of revenue recognition relating to network revenues.

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

Regional Cost Sharing Revenues are generated from transmission customers throughout RTO regions for their use of our MISO Regulated Operating Subsidiaries’ network upgrade projects that are eligible for regional cost sharing under provisions of the MISO tariff, including MVPs. Additionally, certain projects at ITC Great Plains are eligible for recovery through a region-wide charge under provisions of the SPP tariff. Regional cost sharing revenues are treated as a reduction to the net network revenue requirement under our cost-based Formula Rates.

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

Scheduling, Control and Dispatch Revenues are allocated to our MISO Regulated Operating Subsidiaries by MISO as compensation for the services performed in operating the transmission system. Such services include monitoring of reliability data, current and next day analysis, implementation of emergency procedures and outage coordination and switching.

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

Operating Expenses

Operation and Maintenance Expenses consist primarily of the costs for contractors that operate and maintain our transmission systems as well as our personnel involved in operation and maintenance activities.

Operation expenses include activities related to control area operations, which involve balancing loads and generation and transmission system operations activities, including monitoring the status of our transmission lines and stations. Rental expenses relating to land easements, including METC's Easement Agreement, are also recorded within operation expenses.

Maintenance expenses include preventive or planned activities, such as vegetation management, tower painting and equipment inspections, as well as reactive maintenance for equipment failures.

General and Administrative Expenses consist primarily of costs for personnel in our legal, information technology, finance, regulatory, human resources, community relations and communication functions, general office expenses and fees for professional services. Professional services are principally composed of outside legal, consulting, audit and information technology services.

Depreciation and Amortization Expenses consist primarily of depreciation of property, plant and equipment using the straight-line method of accounting. Additionally, this consists of amortization of various regulatory and intangible assets.

Taxes Other than Income Taxes consist primarily of property taxes and payroll taxes.

Other Items of Income or Expense

Interest Expense consists primarily of interest on debt at ITC Holdings and our Regulated Operating Subsidiaries. Additionally, the amortization of debt financing expenses and loss on extinguishment of debt are recorded to interest expense. An allowance for borrowed funds used during construction is included in property, plant and equipment accounts and treated as a reduction to interest expense. The amortization of gains and losses on settled and terminated derivative financial instruments is recorded to interest expense. The interest portion of the refunds relating to the MISO ROE Complaints is also recorded to interest expense.

Allowance for Equity Funds Used During Construction ("AFUDC equity") is recorded as an item of other income and is included in property, plant and equipment accounts. The allowance represents a return on equity at our Regulated Operating Subsidiaries used for construction purposes in accordance with the FERC regulations. The capitalization rate applied to the construction work in progress balance is based on the proportion of equity to total capital (which currently includes equity and long-term debt) and the authorized return on equity for our Regulated Operating Subsidiaries.

Income Tax Provision

Income tax provision consists of current and deferred federal and state income taxes.

Results of Operations

The following table summarizes historical operating results for the periods indicated:

(In millions of USD)	Year Ended December 31, 2020	Year Ended December 31, 2019	Increase (Decrease)	Percentage Increase (Decrease)	Year Ended December 31, 2018	Increase (Decrease)	Percentage Increase (Decrease)
OPERATING REVENUES							
Transmission and other services	$ 1,290	$ 1,286	$ 4	— %	$ 1,192	$ 94	8 %
Formula Rate true-up	8	41	(33)	(80)%	(36)	77	(214)%
Total operating revenue	1,298	1,327	(29)	(2)%	1,156	171	15 %
OPERATING EXPENSES							
Operation and maintenance	87	113	(26)	(23)%	109	4	4 %
General and administrative	115	138	(23)	(17)%	127	11	9 %
Depreciation and amortization	219	203	16	8 %	180	23	13 %
Taxes other than income taxes	124	118	6	5 %	109	9	8 %
Other operating (income) and expenses, net	—	—	—	n/a	(4)	4	(100)%
Total operating expenses	545	572	(27)	(5)%	521	51	10 %
OPERATING INCOME	753	755	(2)	— %	635	120	19 %
OTHER EXPENSES (INCOME)							
Interest expense, net	240	224	16	7 %	224	—	— %
Allowance for equity funds used during construction	(27)	(29)	2	(7)%	(33)	4	(12)%
Other (income) and expenses, net	(3)	—	(3)	n/a	3	(3)	(100)%
Total other expenses (income)	210	195	15	8 %	194	1	1 %
INCOME BEFORE INCOME TAXES	543	560	(17)	(3)%	441	119	27 %
INCOME TAX PROVISION	136	132	4	3 %	111	21	19 %
NET INCOME	$ 407	$ 428	$ (21)	(5)%	$ 330	$ 98	30 %

Operating Revenues

Year ended December 31, 2020 compared to year ended December 31, 2019

The following table sets forth the components of and changes in operating revenues for the year ended December 31, 2020 and 2019 which included revenue accruals and deferrals in Note 6 to the consolidated financial statements:

(In millions of USD)	2020 Amount	2020 Percentage	2019 Amount	2019 Percentage	Increase (Decrease)	Percentage Increase (Decrease)
Network revenues (a)	$ 852	66 %	$ 836	63 %	$ 16	2 %
Regional cost sharing revenues (a)	362	28 %	371	28 %	(9)	(2)%
Point-to-point	13	1 %	13	1 %	—	— %
Scheduling, control and dispatch (a)	20	2 %	17	1 %	3	18 %
Other	19	1 %	21	2 %	(2)	(10)%
Recognition of net liabilities for MISO ROE Complaints	32	2 %	69	5 %	(37)	(54)%
Total	$ 1,298	100 %	$ 1,327	100 %	$ (29)	(2)%

(a) Includes a portion of the Formula Rate true-up of $8 million and $41 million for the year ended December 31, 2020 and 2019, respectively.

Operating revenues decreased during the year ended December 31, 2020, compared to the same period in 2019, primarily due to differences in the amount of adjustments that were made in each period to the net refund liabilities recorded related to the MISO ROE Complaints, as described in Note 18 to the consolidated financial statements. The adjustments resulted in a net increase in operating revenues of $32 million for the year ended December 31, 2020, compared to an increase in operating revenues of $69 million for the year ended 2019.

Excluding the impact of the adjustments for the MISO ROE Complaints, operating revenues increased due to a higher rate base associated with higher balances of property, plant and equipment in service for the year ended December 31, 2020, compared to the same period in 2019. The increase was partially offset by cost saving measures that were implemented as a result of the COVID-19 pandemic, which resulted in lower revenue requirements to customers as these costs are recovered through rates.

Operating Expenses

Operation and maintenance expenses

Year ended December 31, 2020 compared to year ended December 31, 2019

Operation and maintenance expense decreased primarily due to lower expenses associated with substation and overhead line maintenance activities and vegetation management resulting from the temporary cost saving measures that were implemented in response to the COVID-19 pandemic.

General and administrative expenses

Year ended December 31, 2020 compared to year ended December 31, 2019

General and administrative expenses decreased due to reduced general business expenses of $4 million and professional advisory services of $7 million primarily resulting from the temporary cost saving measures that were implemented in response to the COVID-19 pandemic. The decrease was also due to lower compensation-related expenses, primarily due to a decrease in share-based compensation expense of $7 million.

Depreciation and amortization expenses

Year ended December 31, 2020 compared to year ended December 31, 2019

Depreciation and amortization expenses increased primarily due to a higher depreciable base resulting from property, plant and equipment in-service additions.

Other Expenses (Income)

Interest Expense, Net

Year ended December 31, 2020 compared to year ended December 31, 2019

Interest expense, net increased due to a decrease in the amount of reversals of interest expense recorded in 2020, as compared to the amount recorded in 2019, pursuant to FERC orders on the MISO ROE Complaints, as described in Note 18 to the consolidated financial statements. Interest expense, net also increased due to higher debt balances and higher amortization of interest as a result of losses on interest rate swaps terminated in 2020, as discussed in Note 10 to the consolidated financial statements.

Income Tax Provision

Year ended December 31, 2020 compared to year ended December 31, 2019

Our effective tax rates for the years ended December 31, 2020 and 2019 were 25.0% and 23.6%, respectively. Our effective tax rate as of December 31, 2020 exceeded our 21% statutory federal income tax rate primarily due to state income taxes, partially offset by AFUDC equity. The amount of income tax expense relating to AFUDC equity was recognized as a regulatory asset and is not included in the income tax provision. See Note 11 to the consolidated financial statements for further discussion regarding our income tax provision.

Liquidity and Capital Resources

We expect to maintain our approach of funding our future capital requirements with cash from operations at our Regulated Operating Subsidiaries, our existing cash and cash equivalents, future issuances under our commercial paper program and amounts available under our revolving credit agreements (the terms of which are described in Note 10 to the consolidated financial statements). In addition, we may from time to time secure debt funding in the capital markets, although we can provide no assurance that we will be able to obtain financing on favorable terms or at all. As market conditions warrant, we may also from time to time repurchase debt securities issued by us, in the open market, in privately negotiated transactions, by tender offer or otherwise. We expect that our capital requirements will arise principally from our need to:

- Fund capital expenditures (including purchase commitments as described in Note 18) at our Regulated Operating Subsidiaries. Our plans with regard to property, plant and equipment investments are described in detail above under "— Capital Investment and Operating Results Trends."
- Fund our debt service requirements, including principal repayments and periodic interest payments, which are further described in detail below.
- Fund working capital requirements.

In addition to the expected capital requirements above, any adverse determinations or settlements relating to the regulatory matters or contingencies described in Notes 6 and 18 to the consolidated financial statements would result in additional capital requirements.

We believe that we have sufficient capital resources to meet our currently anticipated short-term needs. However, we rely on both internal and external sources of liquidity to provide working capital and fund capital investments. The COVID-19 pandemic has impacted the global economy and capital markets in various ways, including negative impacts which have varied in duration and magnitude. An extended period of economic disruption could impact our ability to access the capital markets requiring us to seek alternative forms of financing which could negatively impact our liquidity and capital resources. ITC Holdings' sources of cash are dividends and other payments received by us from our Regulated Operating Subsidiaries and any of our other subsidiaries as well as the proceeds raised from the sale of our debt securities. Each of our Regulated Operating Subsidiaries, while wholly-owned by ITC Holdings, is legally distinct from ITC Holdings and has no obligation, contingent or otherwise, to make funds available to us.

We expect to continue to utilize our commercial paper program and revolving credit agreements as well as our cash and cash equivalents as needed to meet our short-term cash requirements. As of December 31, 2020, we had consolidated indebtedness under our revolving credit agreements of $198 million, with unused capacity under our revolving credit agreements of $702 million. ITC Holdings had $67 million of commercial paper issued and outstanding, net of discount, as of December 31, 2020, with the ability to issue an additional $333 million under the commercial paper program. In 2020, we paid $9 million of interest and commitment fees under our revolving and term loan credit agreements and commercial paper program.

To address our future capital requirements, we expect that we will need to obtain additional long-term debt financing. As of December 31, 2020, we had various notes and bonds outstanding with terms, including fixed interest rate and principal payment terms, specific to each borrowing. Maturity dates for these long-term debt issuances range from 2022 to 2055. Total future interest payment obligations associated with these existing fixed-rate, long-term debt obligations were $4 billion as of December 31, 2020, with expected interest payment obligations of $240 million due within the next twelve months. Certain of our capital projects could be delayed if we experience difficulties in accessing capital pursuant to complications from COVID-19, or otherwise. We expect to be able to obtain such additional financing as needed, in amounts and upon terms that will be acceptable to us due to our strong credit ratings and our historical ability to obtain financing. See Note 10 to the consolidated financial statements for a detailed discussion of our debt activity, including the commercial paper program and our term loan and revolving credit agreements, during the years ended December 31, 2020 and 2019.

METC has a contractual obligation through December 31, 2050 for an Easement Agreement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which the transmission lines cross. The cost for use of the rights-of-way is $10 million per year. See Note 18 for additional details related to the easement.

We have certain obligations including contingent liabilities and other current and long-term liabilities, that have uncertainty regarding the timing and any amount of future cash flows necessary to settle these obligations. Such items include:

- long-term incentive awards;
- pension and other postretirement obligations;
- regulatory liabilities related to asset removal costs and refundable income taxes; and

- liabilities to refund deposits from generators for transmission network upgrades.

We have material exposure to LIBOR through the revolving credit agreements of ITC Holdings and certain of our Regulated Operating Subsidiaries. It is expected that LIBOR will be phased out beginning in late 2021. We believe that SOFR, the rate selected as the preferred alternative to LIBOR, will be an acceptable replacement rate when LIBOR is discontinued. However, we cannot reasonably estimate the expected impact of the planned discontinuation of LIBOR at this time.

Credit Ratings

Credit ratings by nationally recognized statistical rating agencies are an important component of our liquidity profile. Credit ratings relate to our ability to issue debt securities and the cost to borrow money and should not be viewed as a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time and each rating should be evaluated independently of any other rating. Our current credit ratings are displayed in the following table. An explanation of these ratings may be obtained from the respective rating agency.

	S&P		Moody's	
	Rating	Outlook	Rating	Outlook
ITC Holdings				
Senior Unsecured Notes	BBB+	Negative	Baa2	Stable
Commercial Paper	A-2	Negative	Prime-2	Stable
ITCTransmission				
First Mortgage Bonds	A	Negative	A1	Stable
METC				
Senior Secured Notes	A	Negative	A1	Stable
ITC Midwest				
First Mortgage Bonds	A	Negative	A1	Stable
ITC Great Plains				
First Mortgage Bonds	A	Negative	A1	Stable

Covenants

Our debt instruments contain numerous financial and operating covenants that place significant restrictions on certain transactions, such as incurring additional indebtedness, engaging in sale and lease-back transactions, creating liens or other encumbrances, entering into mergers, consolidations, liquidations or dissolutions, creating or acquiring subsidiaries and selling or otherwise disposing of all or substantially all of our assets. In addition, the covenants require us to meet certain financial ratios, such as maintaining certain debt to capitalization ratios and certain funds from operations to debt levels. As of December 31, 2020, we were not in violation of any debt covenant. In the event of a downgrade in our credit ratings, none of the covenants would be directly impacted, although the borrowing costs under our revolving credit agreements may increase.

Cash Flows

The following table summarizes cash flows for the periods indicated:

	Year Ended December 31,		
(In millions of USD)	2020	2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 407	$ 428	$ 330
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	219	203	180
Recognition, refund and collection of revenue accruals and deferrals — including accrued interest	(47)	(55)	17
Deferred income tax expense	138	135	107
Other	(85)	(82)	19
Net cash provided by operating activities	632	629	653
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(885)	(865)	(769)
Contributions in aid of construction	2	10	21
Other	5	1	1
Net cash used in investing activities	(878)	(854)	(747)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net issuance/repayment of debt (including commercial paper and revolving and term loan credit agreements)	561	463	238
Dividends to ITC Investment Holdings	(330)	(250)	(200)
Refundable deposits from and repayments to generators for transmission network upgrades, net	50	11	3
Settlement of interest rate swaps	(23)	—	—
Other	(12)	(3)	(5)
Net cash provided by financing activities	246	221	36
NET INCREASE (DECREASE) IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	—	(4)	(58)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — Beginning of period	6	10	68
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — End of period	$ 6	$ 6	$ 10

Cash Flows From Operating Activities

Year ended December 31, 2020 compared to year ended December 31, 2019

Net cash provided by operating activities was $632 million and $629 million for the year ended December 31, 2020 and 2019, respectively. The increase in cash provided by operating activities was due primarily to lower payments for operation and maintenance expenses and general and administrative expenses and the timing of the settlement of payables for operating activities. This increase was partially offset by an increase in payments pursuant to our long-term incentive plans of $22 million, the refunds, including interest, related to the MISO ROE Complaints of $31 million and higher property tax payments of $14 million during the year ended December 31, 2020 compared to the same period in 2019.

Cash Flows From Investing Activities

Year ended December 31, 2020 compared to year ended December 31, 2019

Net cash used in investing activities was $878 million and $854 million for the year ended December 31, 2020 and 2019, respectively. The increase in cash used in investing activities was primarily due to an increase in capital expenditures of $20 million during the year ended December 31, 2020 compared to the same period in 2019.

Cash Flows From Financing Activities

Year ended December 31, 2020 compared to year ended December 31, 2019

Net cash provided by financing activities was $246 million and $221 million for the year ended December 31, 2020 and 2019, respectively. The increase in cash provided by financing activities was due primarily to an increase in issuances of long-term debt of $855 million, a decrease in retirement of long-term debt of $168 million and an increase in net refundable deposits for transmission network upgrades of $39 million during the year ended December 31, 2020 compared to the same period in 2019. These increases were partially offset by increases in net repayments under our revolving and term loan credit agreements of $592 million, net repayments of commercial paper of $333 million, dividend payments of $80 million and settlement of interest rate swaps of $23 million during the year ended December 31, 2020 compared to the same period in 2019. See Note 10 to the consolidated financial statements for detail on the issuances and retirements of debt, borrowings under our term loan credit agreement and a description of our revolving credit agreements and commercial paper program.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in accordance with GAAP. The preparation of these consolidated financial statements requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies requires judgments regarding future events.

These estimates and judgments, in and of themselves, could materially impact the consolidated financial statements and disclosures based on varying assumptions, as future events rarely develop exactly as forecasted, and even the best estimates routinely require adjustment.

The following accounting policies are the most significant to the portrayal of our financial condition and results of operations and/or that require management's most difficult, subjective or complex judgments.

Regulation

Our Regulated Operating Subsidiaries are subject to rate regulation by the FERC. As a result, we apply accounting principles in accordance with the standards set forth by the FASB for accounting for the effects of certain types of regulation. Use of this 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. As described in Note 7 to the consolidated financial statements, we had regulatory assets and liabilities of $264 million and $626 million, respectively, as of December 31, 2020. Future changes in the regulatory and competitive environments could result in discontinuing the application of the accounting standards for the effects of certain types of regulations. If we were to discontinue the application of this guidance on the operations of our Regulated Operating Subsidiaries, we may be required to record losses relating to certain regulatory assets or gains relating to certain regulatory liabilities. We also may be required to record losses of $29 million relating to intangible assets at December 31, 2020 that are described in Note 9 to the consolidated financial statements.

We believe that currently available facts support the continued applicability of the standards for accounting for the effects of certain types of regulation and that all regulatory assets and liabilities are recoverable or refundable under our current rate environment.

Revenue Recognition under Cost-Based Formula Rates with True-Up Mechanism

Our Regulated Operating Subsidiaries recover expenses and earn an authorized return on and recover investments in property, plant and equipment on a current basis, under their forward-looking cost-based Formula Rates with a true-up mechanism.

Under their Formula Rates, our Regulated Operating Subsidiaries use forecasted expenses, property, plant and equipment, point-to-point revenues and other items for the upcoming calendar year to establish their projected revenue requirement and for the MISO Regulated Operating Subsidiaries, their component of the billed network rates for service on their systems from January 1 to December 31 of that year. Our Formula Rates include a true-up mechanism, whereby our Regulated Operating Subsidiaries compare their actual revenue requirements to their billed revenues for each year to determine any over- or under-collection of revenue. The over- or under-collection typically results from differences between the projected revenue requirement used as the basis for billing and actual revenue requirement at each of our Regulated Operating Subsidiaries, or from differences between actual and projected monthly network peak loads at our MISO Regulated Operating Subsidiaries.

The true-up mechanisms under our Formula Rates meet the GAAP requirements for accounting for rate-regulated utilities and the effects of certain alternative revenue programs. Accordingly, revenue is recognized during each reporting period based on actual revenue requirements calculated using the cost-based Formula Rates. Our Regulated Operating Subsidiaries accrue or defer revenues to the extent that their actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. The true-up amount is automatically reflected in customer bills within two years under the provisions of the Formula Rates. See Note 7 to the consolidated financial statements for the regulatory assets and liabilities recorded at our Regulated Operating Subsidiaries' as a result of the Formula Rate revenue accruals and deferrals.

Contingent Obligations

We are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject us to environmental, litigation, income tax and other contingencies. We periodically evaluate our exposure to such contingencies and record liabilities for those matters where a loss is considered probable and reasonably estimable. Our liabilities exclude any estimates for legal costs not yet incurred associated with handling these matters, which could be material. The adequacy of liabilities recorded can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect our consolidated financial statements. These events or conditions include, without limitation, the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes and other environmental matters.
- Changes in existing federal income tax laws or IRS regulations.
- Identification and evaluation of lawsuits or complaints in which we may be or have been named as a defendant.
- Resolution or progression of existing matters through the legislative process, the courts, the FERC, the NERC, the IRS or the Environmental Protection Agency.

Refer to Note 18 to the consolidated financial statements for discussion on contingencies, including the MISO ROE Complaints.

Pension and Postretirement Costs

We sponsor certain retirement benefits for our employees, which include retirement pension plans and certain postretirement health care, dental and life insurance benefits. Our periodic costs and obligations associated with these plans are developed from actuarial valuations derived from a number of assumptions, including rates of return on plan assets, discount rates, the rate of increase in health care costs, the amount and timing of plan sponsor contributions and demographic factors such as retirements, mortality and turnover, among others. We evaluate these assumptions annually and update them periodically to reflect our actual experience. Three critical assumptions in determining our periodic costs and obligations are discount rate, expected long-term return on plan assets and the rate of increases in health care costs. The discount rate represents the market rate for synthesized AA-rated zero-coupon bonds with durations corresponding to the expected durations of the benefit obligations and is used to calculate the present value of the expected future cash flows for benefit obligations under our plans. In determining our long-term rate of return on plan assets, we consider the current and expected asset allocations, as well as historical and expected long-term rates of return on those types of asset classes. Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a material effect on our financial condition.

Recent Accounting Pronouncements

See Note 2 to the consolidated financial statements.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.*

Commodity Price Risk

We have commodity price risk at our Regulated Operating Subsidiaries arising from market price fluctuations for materials such as copper, aluminum, steel, oil and gas and other goods used in construction and maintenance activities. Higher costs of these materials are passed on to us by the contractors for these activities. These items affect only cash flows, as the amounts are included as components of net revenue requirement and any higher costs are included in rates under their cost-based Formula Rates.

Interest Rate Risk

Fixed Rate Debt

Based on the borrowing rates currently available for bank loans with similar terms and average maturities, the fair value of our consolidated long-term debt and debt maturing within one year, excluding revolving credit agreements and commercial paper, was $7,119 million at December 31, 2020. The total book value of our consolidated long-term debt and debt maturing within one year, net of discount and deferred financing fees and excluding revolving credit agreements and commercial paper, was $6,097 million at December 31, 2020. We performed an analysis calculating the impact of changes in interest rates on the fair value of long-term debt and debt maturing within one year, excluding revolving credit agreements and commercial paper at December 31, 2020. An increase in interest rates of 10% (from 5.0% to 5.5%, for example) at December 31, 2020 would decrease the fair value of debt by $213 million, and a decrease in interest rates of 10% at December 31, 2020 would increase the fair value of debt by $227 million at that date.

Revolving Credit Agreements

At December 31, 2020, we had a consolidated total of $198 million outstanding under our revolving credit agreements, which are variable rate loans and fair value approximates book value. A 10% increase or decrease in borrowing rates under the revolving credit agreements compared to the weighted average rates in effect at December 31, 2020 would increase or decrease interest expense by less than $1 million for an annual period with a constant borrowing level of $198 million.

Commercial Paper

At December 31, 2020, ITC Holdings had $67 million of commercial paper issued and outstanding, net of discount, under the commercial paper program. Due to the short-term nature of these financial instruments, the carrying value approximates fair value. A 10% increase or decrease in interest rates for commercial paper would increase or decrease interest expense by less than $1 million for an annual period with a continuous level of commercial paper outstanding of $67 million.

Derivative Instruments and Hedging Activities

We use derivative financial instruments, including interest rate swap contracts, to manage our exposure to fluctuations in interest rates. The use of these financial instruments mitigates exposure to these risks and the variability of our operating results. We are not a party to leveraged derivatives and do not enter into derivative financial instruments for trading or speculative purposes.

In May 2020, we terminated $450 million of 5-year interest rate swap contracts that managed interest rate risk associated with the $700 million Senior Notes at ITC Holdings with a maturity date of May 14, 2030 as described in Note 10 to the consolidated financial statements. At December 31, 2020, ITC Holdings did not have any interest rate swaps outstanding.

Credit Risk

Our credit risk is primarily with DTE Electric, Consumers Energy and IP&L, which were responsible for approximately 21.6%, 23.9% and 23.9%, respectively, or $265 million, $292 million and $292 million, respectively, of our consolidated billed revenues for the year ended December 31, 2020. These percentages and amounts of total billed revenues of DTE Electric, Consumers Energy and IP&L include the collection of 2018 revenue accruals and deferrals and exclude any amounts for the 2020 revenue accruals and deferrals that were included in our 2020 operating revenues but will not be billed to our customers until 2022. Refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism" for a discussion on the difference between billed revenues and operating revenues. Under DTE Electric's and Consumers Energy's current rate structure, DTE Electric and Consumers Energy include in their retail rates the actual cost of transmission services provided by ITCTransmission and METC, respectively, in their billings to their customers, effectively passing through to end-use consumers the total cost of transmission service. IP&L currently includes in their retail rates an allowance for transmission services provided by ITC Midwest in their billings to their customers. However, any financial difficulties experienced by DTE Electric, Consumers Energy or IP&L may affect their ability to make payments for transmission service to ITCTransmission, METC, and ITC Midwest, which could negatively impact our business. MISO, as our MISO Regulated Operating Subsidiaries' billing agent, bills DTE Electric, Consumers Energy, IP&L and other customers on a monthly basis and collects fees for the use of the MISO Regulated Operating Subsidiaries' transmission systems. SPP is the billing agent for ITC Great Plains and bills transmission customers for the use of ITC Great Plains transmission systems. MISO and SPP have implemented strict credit policies for its members' customers, which include customers using our transmission systems. Specifically, MISO and SPP require a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit scoring model and other factors, from any customer using a member's transmission system.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.*

The following financial statements and schedules are included herein:

	Page
Management’s Report on Internal Control over Financial Reporting	43
Report of Independent Registered Public Accounting Firm	44
Consolidated Statements of Financial Position as of December 31, 2020 and 2019	46
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2020, 2019 and 2018	47
Consolidated Statements of Changes in Stockholder’s Equity for the Years Ended December 31, 2020, 2019 and 2018	48
Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019 and 2018	49
Notes to Consolidated Financial Statements	50
Schedule I — Condensed Financial Information of Registrant	129

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is designed to provide reasonable, not absolute, assurance as to the reliability of our financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting determined to be effective can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Under management's supervision, an evaluation of the design and effectiveness of our internal control over financial reporting was conducted based on the criteria set forth in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Our assessment included documenting, evaluating and testing of the design and operating effectiveness of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2020.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
ITC Holdings Corp.
Novi, Michigan

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of ITC Holdings Corp. and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of comprehensive income, changes in stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes and the schedule listed in the Index at Item 15 (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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

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 Public Company Accounting Oversight Board (United States) (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 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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.

Regulatory Matters — Impact of rate regulation on the financial statements — Refer to Notes 3, 6 and 7 to the financial statements

Critical Audit Matter Description

The Company's regulated operating subsidiaries are subject to rate regulation by the Federal Energy Regulatory Commission (the "regulatory agency"). 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. The Company's rates are subject to regulatory rate-setting processes through a formula rate with a true-up mechanism, including an authorized return on equity. Regulatory decisions can have an impact on rates, recovery of certain costs, including the costs of transmission assets and regulatory assets, conditions of service, accounting, financing authorization and operating-related matters, the timely recovery of costs and the return on equity. 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; and income taxes.

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 potential refunds to customers. While the Company has indicated they expect to recover costs from customers through regulated rates, there is a risk that the formula inputs remain subject to legal challenge at the regulatory agency. The Company uses the formula to calculate annual revenue requirements unless the regulatory agency determines the resulting rates to be unjust and unreasonable. Auditing these judgments required especially subjective judgment and specialized knowledge of accounting for rate regulation and the rate-setting process due to their inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the regulatory agency included the following, among others:

- We evaluated 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.
- We assessed 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 future reduction in rates and the ability to earn a reasonable return on equity.
- For regulatory matters in process, we inspected the annual formula rate filings and open complaints for any evidence that might contradict management's assertions. We obtained an analysis from management, regarding cost recoveries or potential future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ DELOITTE & TOUCHE LLP

Detroit, Michigan
February 11, 2021

We have served as the Company's auditor since 2001.

ITC HOLDINGS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(In millions of USD, except share data)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 4	$ 4
Accounts receivable	114	117
Inventory	42	39
Regulatory assets	52	12
Prepaid and other current assets	12	15
Total current assets	224	187
Property, plant and equipment (net of accumulated depreciation and amortization of $2,055 and $1,930, respectively)	9,327	8,582
Other assets		
Goodwill	950	950
Intangible assets (net of accumulated amortization of $46 and $42, respectively)	29	33
Regulatory assets	212	229
Other assets	83	77
Total other assets	1,274	1,289
TOTAL ASSETS	$ 10,825	$ 10,058
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable	$ 130	$ 82
Accrued compensation	55	61
Accrued interest	55	48
Accrued taxes	61	66
Regulatory liabilities	14	123
Refundable deposits and advances for construction	37	27
Debt maturing within one year	67	235
Other current liabilities	18	16
Total current liabilities	437	658
Accrued pension and postretirement liabilities	59	73
Deferred income taxes	1,013	873
Regulatory liabilities	612	584
Refundable deposits	65	19
Other liabilities	50	47
Long-term debt	6,295	5,572
Commitments and contingent liabilities (Notes 6 and 18)		
TOTAL LIABILITIES	8,531	7,826
STOCKHOLDER'S EQUITY		
Common stock, without par value, 235,000,000 shares authorized, 224,203,112 shares issued and outstanding at December 31, 2020 and 2019	892	892
Retained earnings	1,410	1,333
Accumulated other comprehensive (loss) income	(8)	7
Total stockholder's equity	2,294	2,232
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 10,825	$ 10,058

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
OPERATING REVENUES			
Transmission and other services	$ 1,290	$ 1,286	$ 1,192
Formula Rate true-up	8	41	(36)
Total operating revenue	1,298	1,327	1,156
OPERATING EXPENSES			
Operation and maintenance	87	113	109
General and administrative	115	138	127
Depreciation and amortization	219	203	180
Taxes other than income taxes	124	118	109
Other operating (income) and expense, net	—	—	(4)
Total operating expenses	545	572	521
OPERATING INCOME	753	755	635
OTHER EXPENSES (INCOME)			
Interest expense, net	240	224	224
Allowance for equity funds used during construction	(27)	(29)	(33)
Other (income) and expenses, net	(3)	—	3
Total other expenses (income)	210	195	194
INCOME BEFORE INCOME TAXES	543	560	441
INCOME TAX PROVISION	136	132	111
NET INCOME	407	428	330
OTHER COMPREHENSIVE (LOSS) INCOME			
Derivative instruments, net of tax (Note 14)	(15)	3	1
TOTAL OTHER COMPREHENSIVE (LOSS) INCOME, NET OF TAX	(15)	3	1
TOTAL COMPREHENSIVE INCOME	$ 392	$ 431	$ 331

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY

(In millions of USD)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholder's Equity
BALANCE, DECEMBER 31, 2017	$ 892	$ 1,026	$ 2	$ 1,920
Opening balance reclassification	—	(1)	1	—
Net income	—	330	—	330
Dividends to ITC Investment Holdings	—	(200)	—	(200)
Other comprehensive income, net of tax (Note 14)	—	—	1	1
BALANCE, DECEMBER 31, 2018	$ 892	$ 1,155	$ 4	$ 2,051
Net income	—	428	—	428
Dividends to ITC Investment Holdings	—	(250)	—	(250)
Other comprehensive income, net of tax (Note 14)	—	—	3	3
BALANCE, DECEMBER 31, 2019	$ 892	$ 1,333	$ 7	$ 2,232
Net income	—	407	—	407
Dividends to ITC Investment Holdings	—	(330)	—	(330)
Other comprehensive (loss), net of tax (Note 14)	—	—	(15)	(15)
BALANCE, DECEMBER 31, 2020	$ 892	$ 1,410	$ (8)	$ 2,294

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
(In millions of USD)	2020	2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 407	$ 428	$ 330
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	219	203	180
Recognition, refund and collection of revenue accruals and deferrals — including accrued interest	(47)	(55)	17
Deferred income tax expense	138	135	107
Allowance for equity funds used during construction	(27)	(29)	(33)
Share-based compensation	25	32	6
Other	4	10	4
Changes in assets and liabilities, exclusive of changes shown separately:			
Accounts receivable	—	(10)	17
Income tax receivable	—	1	14
Accounts payable	4	(11)	6
Accrued interest	7	(2)	(10)
Accrued compensation	(14)	10	1
Accrued taxes	(3)	3	7
Net refund payments and adjustments related to return on equity complaints	(65)	(82)	6
Other current and non-current assets and liabilities, net	(16)	(4)	1
Net cash provided by operating activities	632	629	653
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(885)	(865)	(769)
Contributions in aid of construction	2	10	21
Other	5	1	1
Net cash used in investing activities	(878)	(854)	(747)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	1,030	175	400
Borrowings under revolving credit agreements	1,495	1,090	832
Borrowings under term loan credit agreements	275	200	—
Net (repayment) issuance of commercial paper	(133)	200	—
Retirement of long-term debt — including extinguishment of debt costs	(35)	(203)	(100)
Repayments of revolving credit agreements	(1,596)	(999)	(844)
Repayments of term loan credit agreements	(475)	—	(50)
Dividends to ITC Investment Holdings	(330)	(250)	(200)
Refundable deposits from generators for transmission network upgrades	60	19	6
Repayment of refundable deposits from generators for transmission network upgrades	(10)	(8)	(3)
Settlement of interest rate swaps	(23)	—	—
Other	(12)	(3)	(5)
Net cash provided by financing activities	246	221	36
NET INCREASE (DECREASE) IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	—	(4)	(58)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — Beginning of period	6	10	68
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — End of period	$ 6	$ 6	$ 10

See notes to consolidated financial statements.

ITC HOLDINGS CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

ITC Holdings and its subsidiaries are engaged in the transmission of electricity in the United States. ITC Holdings is a wholly-owned subsidiary of ITC Investment Holdings. Fortis owns a majority indirect equity interest in ITC Investment Holdings, with GIC holding an indirect equity interest of 19.9%. Through our Regulated Operating Subsidiaries, we own, operate, maintain and invest in high-voltage electric transmission systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas, and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to our transmission systems.

Our Regulated Operating Subsidiaries are independent electric transmission utilities, with rates regulated by the FERC and established on a cost-of-service model. ITCTransmission's service area is located in southeastern Michigan, while METC's service area covers approximately two-thirds of Michigan's Lower Peninsula and is contiguous with ITCTransmission's service area. ITC Midwest's service area is located in portions of Iowa, Minnesota, Illinois and Missouri and ITC Great Plains currently owns assets located in Kansas and Oklahoma. MISO bills and collects revenues from the MISO Regulated Operating Subsidiaries' customers. SPP bills and collects revenue from ITC Great Plains' customers. ITC Interconnection currently owns assets in Michigan and earns revenues based on its facilities reimbursement agreement with a merchant generating company.

Recent Developments Regarding the COVID-19 Pandemic

In March 2020, the World Health Organization declared COVID-19 a pandemic. Efforts to control the recent outbreak of COVID-19 have resulted in impacts to businesses and facilities in various industries around the world, such as operating restrictions and closures, and disruptions to the global economy and supply chains. The COVID-19 pandemic has and will continue to impact our customers throughout our operating footprint. To date, COVID-19 has not had a material impact on our net income. However, we have implemented various temporary cost saving measures related to operating expenses, including operation and maintenance expenses and general and administrative expenses, in an attempt to reduce costs that are collected from customers through our Formula Rates.

The duration and total impact on our operations from COVID-19 is unknown at this time and will ultimately depend on the duration and severity of the pandemic, the length that the various business restrictions are in effect, the impact of recent resurgences of COVID-19 cases and deaths in the United States, and the efficacy and distribution of COVID-19 vaccines. We are continuing to monitor developments involving our workforce, customers and suppliers and cannot predict whether COVID-19 will have a material impact on our consolidated results of operations, cash flows or financial condition. We are also monitoring the evolving situation and guidance from federal, state and local public health authorities. We are taking steps to mitigate the potential risks to us and our employees posed by COVID-19, including enabling remote work arrangements for employees when appropriate, and are following all government requirements to reduce the transmission of COVID-19.

Monthly Network Peak Load

For our MISO Regulated Operating Subsidiaries, monthly network peak loads are used for billing network revenues, which currently is the largest component of our operating revenues. One of the primary factors that impacts our collection of revenues is actual monthly network peak load, which is impacted by a number of factors including network usage and weather. Although monthly network peak loads do not impact our recognition of operating revenues, actual network load affects the timing of collection of our cash flows from transmission service. During 2020, actual monthly network peak load for our MISO Regulated Operating Subsidiaries decreased compared to pre-COVID-19 forecasted load. This decrease was primarily as a result of reductions in, or suspension of, operations for many businesses and facilities in our operating footprint due to COVID-19. While the decrease in monthly network peak load was significant in the early months of the pandemic, the impact of COVID-19 on monthly network peak loads became less pronounced over the second half of the year. We are unable to predict the possible future impacts of COVID-19, weather and other factors on monthly network peak loads at our MISO Regulated Operating Subsidiaries.

2. RECENT ACCOUNTING PRONOUNCEMENTS

Recently Adopted Pronouncements

Accounting for Cloud Computing Arrangements

In August 2018, the FASB issued authoritative guidance to address the accounting for implementation costs incurred in a cloud computing agreement that is a service contract. The new standard aligns the accounting for implementation costs incurred in a cloud computing arrangement as a service contract with existing guidance on capitalizing costs associated with developing or obtaining internal-use software. In addition, the new guidance requires entities to expense capitalized implementation costs of a cloud computing arrangement that is a service contract over the term of the agreement and to present the expense in the same income statement line item as the hosting fees. The guidance was effective for fiscal years beginning after December 15, 2019 with either prospective or retrospective adoption permitted. We adopted the standard prospectively on January 1, 2020. Adoption of this standard did not have a material impact on our consolidated financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

A summary of the major accounting policies followed in the preparation of the accompanying consolidated financial statements, which conform to GAAP, is presented below:

Principles of Consolidation — ITC Holdings consolidates its majority owned subsidiaries. We eliminate all intercompany balances and transactions.

Use of Estimates — The preparation of the consolidated financial statements requires us to use estimates and assumptions that impact the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results may differ from our estimates.

Regulation — Our Regulated Operating Subsidiaries are subject to the regulatory jurisdiction of the FERC, which issues orders pertaining to rates, recovery of certain costs, including the costs of transmission assets and regulatory assets, conditions of service, accounting, financing authorization and operating-related matters. The utility operations of our Regulated Operating Subsidiaries meet the accounting standards set forth by the FASB for the accounting effects of certain types of regulation. These accounting standards recognize the cost based rate setting process, which results in differences in the application of GAAP between regulated and non-regulated businesses. These standards require the recording of regulatory assets and liabilities for certain transactions that would have been recorded as revenue and expense in non-regulated businesses. Regulatory assets represent costs that will be included as a component of future tariff rates and regulatory liabilities represent amounts provided in the current tariff rates that are intended to recover costs expected to be incurred in the future or amounts to be refunded to customers.

Cash and Cash Equivalents — We consider all unrestricted highly-liquid temporary investments with an original maturity of three months or less at the date of purchase to be cash equivalents.

Restricted Cash and Restricted Cash Equivalents — Restricted cash and restricted cash equivalents include cash and cash equivalents that are legally or contractually restricted for use or withdrawal or are formally set aside for a specific purpose.

Accounts Receivable Reserve — We recognize losses for uncollectible accounts based on the current expected credit loss model. As of December 31, 2020, 2019 and 2018 we did not have an accounts receivable reserve.

Inventories — Materials and supplies inventories are valued at average cost. Additionally, the costs of warehousing activities are recorded here and included in the cost of materials when requisitioned.

Property, Plant and Equipment — Depreciation and amortization expense on property, plant and equipment was $209 million, $194 million and $170 million for 2020, 2019 and 2018, respectively.

Property, plant and equipment in service at our Regulated Operating Subsidiaries is stated at its original cost when first devoted to utility service. The gross book value of assets retired less salvage proceeds is charged to accumulated depreciation. The provision for depreciation of transmission assets is a significant component of our Regulated Operating Subsidiaries' cost of service under FERC-approved rates. Depreciation is computed over the estimated useful lives of the assets using the straight-line method for financial reporting purposes and accelerated methods for income tax reporting purposes. The composite depreciation rate for our Regulated Operating Subsidiaries included in our consolidated statements of comprehensive income was 2.0% for 2020, 2019 and 2018. The composite depreciation rates include depreciation primarily on transmission station equipment, towers, poles and overhead and underground lines that have a useful life ranging from 45 to 60 years. The portion of depreciation expense related to asset removal costs is added to regulatory liabilities or deducted from regulatory assets and removal costs incurred are deducted from regulatory liabilities or added to regulatory assets. Certain of our Regulated Operating Subsidiaries capitalize to property, plant and equipment AFUDC in accordance with the FERC regulations. AFUDC represents the composite cost incurred to fund the construction of assets, including interest expense and a return on equity capital devoted to construction of assets. The interest component of AFUDC was a reduction to interest expense of $7 million for 2020, $8 million for 2019 and $9 million for 2018.

For acquisitions of property, plant and equipment greater than the net book value (other than asset acquisitions accounted for under the purchase method of accounting that result in goodwill), the acquisition premium is recorded to property, plant and equipment and amortized over the estimated remaining useful lives of the assets using the straight-line method for financial reporting purposes and accelerated methods for income tax reporting purposes.

Property, plant and equipment includes capital equipment inventory stated at original cost consisting of items that are expected to be used exclusively for capital projects.

Property, plant and equipment at our non-regulated subsidiaries is stated at its acquired cost. Proceeds from salvage less the net book value of the disposed assets is recognized as a gain or loss on disposal. Depreciation is computed based on the acquired cost less expected residual value and is recognized over the estimated useful lives of the assets on a straight-line method for financial reporting purposes and accelerated methods for income tax reporting purposes.

Generator Interconnection Projects and Contributions in Aid of Construction — Certain capital investment at our Regulated Operating Subsidiaries relates to investments made under GIAs. The GIAs typically consist of both transmission network upgrades, which are a category of upgrades deemed by the FERC to benefit the transmission system as a whole, as well as direct connection facilities, which are necessary to interconnect the generating facility to the transmission system and primarily benefit the generating facility. As a result, GIAs typically require the generator to make a contribution in aid of construction to our Regulated Operating Subsidiaries to cover the cost of certain investments made by us as part of the agreement.

Our investments in transmission facilities are recorded to property, plant and equipment, and are recorded net of any contribution in aid of construction. We also receive refundable deposits from the generator for certain investment in network upgrade facilities in advance of construction, which are recorded to current or non-current liabilities depending on the expected refund date.

Jointly Owned Utility Plant/Coordinated Services — Certain of our Regulated Operating Subsidiaries have agreements with other utilities for the joint ownership of substation assets and transmission lines as described in Note 16. We account for these jointly owned assets by recording property, plant and equipment for the percentage of our undivided ownership interest. Various agreements provide the authority for construction of capital improvements and the operating costs associated with the substations and lines. Generally, each party is responsible for the capital, operation and maintenance and other costs of these jointly owned facilities based upon each participant’s undivided ownership interest, and each participant is responsible for providing its own financing. Our participating share of expenses associated with these jointly held assets are primarily recorded within operation and maintenance expenses on our consolidated statements of comprehensive income.

Fair Value Through Net Income — We have certain investments in mutual funds, including fixed income securities and equity securities that are classified as fair value through net income. The fixed income security investments primarily fund our two supplemental nonqualified, noncontributory, retirement benefit plans for selected management employees as described in Note 12. Gains and losses associated with our mutual funds as described in Note 13 are recorded in earnings.

Impairment of Long-Lived Assets — Other than goodwill, our long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. If the carrying amount of the asset exceeds the expected undiscounted future cash flows generated by the asset, the asset is written down to its estimated fair value and an impairment loss is recognized in our consolidated statements of comprehensive income.

Goodwill and Other Intangible Assets — Goodwill is not subject to amortization; however, goodwill is required to be assessed for impairment, and a resulting write-down, if any, is to be reflected in operating expense. We have goodwill recorded relating to our acquisitions of ITCTransmission and METC and ITC Midwest's acquisition of the IP&L transmission assets. Goodwill is reviewed at the reporting unit level at least annually for impairment and whenever facts or circumstances indicate that the value of goodwill may be impaired. Our reporting units are ITCTransmission, METC and ITC Midwest as each entity represents an individual operating segment to which goodwill has been assigned.

In order to perform an impairment analysis, we have the option of performing a qualitative assessment to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, in which case no further testing is required. If an entity bypasses the qualitative assessment or performs a qualitative assessment but determines that it is more likely than not that a reporting unit's fair value is less than its carrying amount, a quantitative, fair value-based test is performed to assess and measure goodwill impairment, if any. If a quantitative assessment is performed, we determine the fair value of our reporting units using valuation techniques based on discounted future cash flows under various scenarios and consider estimates of market-based valuation multiples for companies within the peer group of our reporting units.

We completed our annual goodwill impairment test for our reporting units as of October 1, 2020 and determined that no impairment exists. There were no events subsequent to October 1, 2020 that indicated impairment of our goodwill. Our intangible assets other than goodwill have finite lives and are amortized over their useful lives. Refer to Note 9 for additional discussion on our goodwill and intangible assets.

Deferred Financing Fees and Discount or Premium on Debt — Costs related to the issuance of long-term debt are generally recorded as a direct deduction from the carrying amount of the related debt and amortized over the life of the debt issue. Debt issuance costs incurred prior to the associated debt funding are presented as an asset. Unamortized debt issuance costs associated with the revolving credit agreements, commercial paper and other similar arrangements are presented as an asset (regardless of whether there are any amounts outstanding under those credit facilities) and amortized over the life of the particular arrangement. The debt discount or premium related to the issuance of long-term debt is recorded to long-term debt and amortized over the life of the debt issue. We recorded $5 million during the years ended December 31, 2020, 2019 and 2018 to interest expense for the amortization of deferred financing fees and debt discounts.

Asset Retirement Obligations — A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within our control. We have identified conditional asset retirement obligations primarily associated with the removal of equipment containing PCBs and asbestos. We record a liability at fair value for a legal asset retirement obligation in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount. We recognize regulatory assets for the timing differences between the incurred costs to settle our legal asset retirement obligations and the recognition of such obligations as applicable for our Regulated Operating Subsidiaries. There were no significant changes to our asset retirement obligations in 2020. Our asset retirement obligations as of December 31, 2020 and 2019 of $6 million are included in other liabilities.

Derivatives and Hedging — We may use derivative financial instruments, including interest rate swap contracts, to manage our exposure to fluctuations in interest rates. For derivative instruments that have been designated and qualify as cash flow hedges of the exposure to variability in expected future cash flows, the unrealized gain or loss on the derivative is initially reported, net of tax, as a component of other comprehensive income (loss) and reclassified to the consolidated statements of comprehensive income when the underlying hedged transaction affects net income. Cash flows related to interest rate swaps that are designated in hedging relationships are generally classified on the consolidated statements of cash flows within cash flows from financing activities. The fair values of derivatives are recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Refer to Note 10 for additional discussion regarding derivative instruments.

Contingent Obligations — We are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject us to environmental, litigation and other risks. We periodically evaluate our exposure to such risks and record liabilities for those matters when a loss is considered probable and reasonably estimable. We reverse the liabilities recorded for those matters when a loss is no longer considered probable or the liabilities are otherwise settled. Our liabilities exclude any estimates for legal costs not yet incurred associated with handling these matters. The adequacy of liabilities can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect our consolidated financial statements.

Revenues — Substantially all of our revenue from contracts with customers is generated from providing transmission services to customers based on tariff rates, as approved by the FERC. Revenues from the transmission of electricity are recognized as services are provided based on our FERC-approved cost-based Formula Rates. We record a reserve for revenue subject to refund when such refund is probable and can be reasonably estimated. This reserve is recorded as a reduction to operating revenues.

The cost-based Formula Rates at our Regulated Operating Subsidiaries include a true-up mechanism that compares the actual revenue requirements of our Regulated Operating Subsidiaries to their billed revenues for each year to determine any over- or under-collection of revenue requirements and we record a revenue deferral or accrual for the difference. The true-up mechanisms under our Formula Rates are considered alternative revenue programs of rate-regulated utilities. Operating revenues arising from these alternative revenue programs are presented on our consolidated statements of comprehensive income in the line “Formula Rate true-up”, which is separate from the reporting of our tariff revenues, which are presented in the line “Transmission and other services”. Only the initial origination of our alternative revenue program revenue is reported in the Formula Rate true-up line on our consolidated statements of comprehensive income. When those amounts are subsequently included in the price of utility service and billed or refunded to customers, we account for that event as the recovery or settlement of the associated regulatory asset or regulatory liability, respectively. Refer to Note 6 under “Cost-Based Formula Rates with True-Up Mechanism” and Note 4 under “Formula Rate True-Up” for a discussion of our revenue accounting under our cost-based Formula Rates.

Share-Based Payment and Employee Share Purchase Plan — Under our long-term incentive plans, we grant long-term incentive awards consisting of PBUs and SBUs. Generally, each PBU and SBU granted is valued based on one share of Fortis common stock traded on the Toronto Stock Exchange, converted to U.S. dollars and settled only in cash. However, certain SBUs granted to the executives may settle in cash, 100% Fortis common stock, or 50% cash and 50% Fortis common stock depending on executives’ settlement elections and whether certain share ownership requirements are met. The awards are classified as liability awards and vest on the date specified in the applicable grant agreements, provided the service and performance criteria, as applicable, are satisfied. The PBUs and SBUs earn dividend equivalents which are also re-measured and settled consistent with the target award at the end of the vesting period.

Compensation cost is recognized over the expected vesting period and remeasured each reporting period based on Fortis’ stock price. The PBUs are also remeasured each reporting period based on the applicable market and performance conditions in the awards. Compensation cost is adjusted for forfeitures in the period in which they occur and the final measure of compensation cost for the awards is based on the cash settlement amount.

We also have an Employee Share Purchase Plan which enables ITC employees to purchase shares of Fortis common stock. Our cost of the plan is based on the value of our contribution, as additional compensation to a participating employee, equal to 10% of an employee’s contribution up to a maximum annual contribution of 1% of an employee's base pay and an amount equal to 10% of all dividends payable by Fortis on the Fortis shares allocated to an employee's ESPP account.

Refer to Note 15 for additional discussion of the plans.

Comprehensive Income (Loss) — Comprehensive income (loss) is the change in common stockholder's equity during a period arising from transactions and events from non-owner sources, including net income and any gain or loss arising from our interest rate swaps.

Income Taxes — Deferred income taxes are recognized for the expected future tax consequences of events that have been recognized in the consolidated financial statements or tax returns. Deferred income tax assets and liabilities are determined based on the differences between the financial statements and the tax bases of various assets and liabilities, using the tax rates expected to be in effect for the year in which the differences are expected to reverse, and classified as non-current in our consolidated statements of financial position.

The accounting standards for uncertainty in income taxes prescribe a recognition threshold and a measurement attribute for tax positions taken, or expected to be taken, in a tax return that may not be sustainable. As of December 31, 2020, we have not recognized any uncertain income tax positions.

We file our federal and Michigan income tax returns as part of the FortisUS consolidated tax returns and we are a party to an intercompany tax sharing agreement that establishes the method for determining tax liabilities that are due and allocating tax attributes that are utilized on the consolidated income tax returns. We continue to file with various other state and city jurisdictions where we have a separate return filing obligation. Our prior consolidated federal tax returns are no longer subject to U.S. federal tax examinations for tax years 2017 and earlier. State and city jurisdictions that remain subject to examination range from tax years 2016 to 2019. In the event we are assessed interest or penalties by any income tax jurisdictions, interest and penalties would be recorded as interest expense and other expense, respectively, in our consolidated statements of comprehensive income.

Refer to Notes 7 and 11 for additional discussion on income taxes.

4. REVENUE

Our total revenues are comprised of revenues which arise from three classifications including transmission services, other services, and Formula Rate true-up. As other services revenue is immaterial, it is presented in combination with transmission services on the consolidated statements of comprehensive income.

Transmission Services

Through our Regulated Operating Subsidiaries, we generate nearly all our revenue from providing electric transmission services over our transmission systems. As independent transmission companies, our transmission services are provided and revenues are received based on our tariffs, as approved by the FERC. The transmission revenue requirements at our Regulated Operating Subsidiaries are set annually using Formula Rates and remain in effect for a one-year period. By updating the inputs to the formula and resulting rates on an annual basis, the revenues at our Regulated Operating Subsidiaries reflect changing operating data and financial performance, including the amount of network load on their transmission systems (for our MISO Regulated Operating Subsidiaries), operating expenses and additions to property, plant and equipment when placed in service, among other items.

We recognize revenue for transmission services over time as transmission services are provided to customers (generally using an output measure of progress based on transmission load delivered). Customers simultaneously receive and consume the benefits provided by the Regulated Operating Subsidiaries' services. We recognize revenue in the amount to which we have the right to invoice because we have a right to consideration in an amount that corresponds directly with the value to the customer of performance completed to date. As billing agents, MISO and SPP independently bill our customers on a monthly basis and collects fees for the use of our transmission systems. No component of the transaction price is allocated to unsatisfied performance obligations.

Transmission service revenue includes an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period. Unbilled revenues are dependent upon a number of factors that require management's judgment including estimates of transmission network load (for the MISO

Regulated Operating Subsidiaries) and preliminary information provided by billing agents. Due to the seasonal fluctuations of actual load, the unbilled revenue amount generally increases during the spring and summer and decreases during the fall and winter. See Note 5 for information on changes in unbilled accounts receivable.

Other Services

Other services revenue consists of rental revenues, easement revenues, and amounts from providing ancillary services. A portion of other services revenue is treated as a revenue credit and reduces gross revenue requirement when calculating net revenue requirement under our Formula Rates. Total other services revenue was $5 million, $7 million and $5 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Formula Rate True-Up

The true-up mechanism under our Formula Rates is considered an alternative revenue program of a rate-regulated utility given it permits our Regulated Operating Subsidiaries to adjust future rates in response to past activities or completed events in order to collect our actual revenue requirements under our Formula Rates. In accordance with our accounting policy, only the current year origination of the true-up is reported as a Formula Rate true-up. See "Cost-Based Formula Rates with True-Up Mechanism" in Note 6 for more information on our Formula Rates.

5. ACCOUNTS RECEIVABLE

The following table presents the components of accounts receivable on the consolidated statements of financial position:

	December 31,			
(In millions of USD)	**2020**	**2019**	**2018**	**2017**
Trade accounts receivable	$ 2	$ 2	$ 2	$ 2
Unbilled accounts receivable	102	102	92	108
Other	10	13	8	9
Total accounts receivable	$ 114	$ 117	$ 102	$ 119

6. REGULATORY MATTERS

Cost-Based Formula Rates with True-Up Mechanism

The transmission revenue requirements at our Regulated Operating Subsidiaries are set annually using Formula Rates and remain in effect for a one-year period. By updating the inputs to the formula and resulting rates on an annual basis, the revenues at our Regulated Operating Subsidiaries reflect changing operational data and financial performance, including the amount of network load on their transmission systems (for our MISO Regulated Operating Subsidiaries), operating expenses and additions to property, plant and equipment when placed in service, among other items. The formula used to derive the rates does not require further action or FERC filings each year, although the formula inputs remain subject to legal challenge at the FERC. Our Regulated Operating Subsidiaries will continue to use the formula to calculate their respective annual revenue requirements unless the FERC determines the resulting rates to be unjust and unreasonable and another mechanism is determined by the FERC to be just and reasonable. See "Rate of Return on Equity Complaints" in Note 18 for detail on ROE matters for our MISO Regulated Operating Subsidiaries and "Incentive Adders for Transmission Rates" discussed in Note 6 herein.

The cost-based Formula Rates at our Regulated Operating Subsidiaries include a true-up mechanism that compares the actual revenue requirements of our Regulated Operating Subsidiaries to their billed revenues for each year to determine any over- or under-collection of revenue requirements. Revenue is recognized for services provided during each reporting period based on actual revenue requirements calculated using the formula. Our Regulated Operating Subsidiaries accrue or defer revenues to the extent that the actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. The amount of accrued or deferred revenues is reflected in future revenue requirements and thus flows through to customer bills within two years under the provisions of our Formula Rates.

The net changes in regulatory assets and liabilities associated with our Regulated Operating Subsidiaries' Formula Rate revenue accruals and deferrals, including accrued interest, were as follows during the year ended December 31, 2020:

(In millions of USD)	Total
Net regulatory assets as of December 31, 2019	$ 3
Net refund of 2018 revenue deferrals and accruals, including accrued interest	40
Net revenue accrual for the year ended December 31, 2020	8
Net accrued interest payable for the year ended December 31, 2020	(1)
Net regulatory assets as of December 31, 2020	$ 50

Regulatory assets and liabilities associated with our Regulated Operating Subsidiaries' Formula Rate revenue accruals and deferrals, including accrued interest, are recorded in the consolidated statements of financial position as follows:

	December 31,	
(In millions of USD)	2020	2019
Current regulatory assets	$ 44	$ 12
Non-current regulatory assets	19	43
Current regulatory liabilities	(1)	(51)
Non-current regulatory liabilities	(12)	(1)
Net regulatory assets	$ 50	$ 3

Incentive Adders for Transmission Rates

The FERC has authorized the use of ROE incentives, or adders, that can be applied to the rates of TOs when certain conditions are met. Our MISO Regulated Operating Subsidiaries and ITC Great Plains utilize ROE adders related to independent transmission ownership and RTO participation.

MISO Regulated Operating Subsidiaries

On April 20, 2018, Consumers Energy, IP&L, Midwest Municipal Transmission Group, Missouri River Energy Services, Southern Minnesota Municipal Power Agency and WPPI Energy filed a complaint with the FERC under section 206 of the FPA, challenging the adders for independent transmission ownership that are included in transmission rates charged by the MISO Regulated Operating Subsidiaries. The adders for independent transmission ownership allowed up to 50 basis points or 100 basis points to be added to the MISO Regulated Operating Subsidiaries' authorized ROE, subject to any ROE cap established by the FERC. On October 18, 2018, the FERC issued an order granting the complaint in part, setting revised adders for independent transmission ownership for each of the MISO Regulated Operating Subsidiaries to 25 basis points, and requiring the MISO Regulated Operating Subsidiaries to include the revised adders, effective April 20, 2018, in their Formula Rates. In addition, the order directed the MISO Regulated Operating Subsidiaries to provide refunds, with interest, for the period from April 20, 2018 through October 18, 2018. The MISO Regulated Operating Subsidiaries began reflecting the 25 basis point adder for independent transmission ownership in transmission rates in November 2018. Refunds of $7 million were primarily made in the fourth quarter of 2018 and were completed in the first quarter of 2019. The MISO Regulated Operating Subsidiaries sought rehearing of the FERC's October 18, 2018 order, and on July 18, 2019, the FERC denied the rehearing request. On September 11, 2019, the MISO Regulated Operating Subsidiaries filed an appeal of the FERC's order in the D.C. Circuit Court. On December 16, 2019, the D.C. Circuit Court established a briefing schedule for the appeal. An initial brief was filed on January 27, 2020 and a reply brief was filed on April 24, 2020. Oral argument on the appeal was held on September 23, 2020. We do not expect the final resolution of this proceeding to have a material adverse impact on our consolidated results of operations, cash flows or financial condition.

For each of the years ended December 31, 2020, 2019 and 2018, the authorized incentive adders for the MISO Regulated Operating Subsidiaries included a 25 basis point adder for independent transmission ownership and a 50 basis point adder for RTO participation. See Note 18 for information regarding the MISO ROE Complaints and the associated impact to the base ROE of our MISO Regulated Operating Subsidiaries.

ITC Great Plains

On June 11, 2019, KCC filed a complaint with the FERC under section 206 of the FPA, challenging the ROE adder for independent transmission ownership that is included in the transmission rate charged by ITC Great Plains. The complaint argues that because ITC Great Plains is similarly situated to our MISO Regulated Operating Subsidiaries with respect to ownership by Fortis and GIC, the same rationale by which the FERC lowered the MISO Regulated Operating Subsidiaries adders for independent transmission ownership, as discussed above, also applies to ITC Great Plains. The adder for independent transmission ownership allowed up to 100 basis points to be added to the ITC Great Plains authorized ROE, subject to any ROE cap established by the FERC. ITC Great Plains filed an answer to the complaint on July 1, 2019 asking the FERC to deny the complaint since KCC showed no evidence that ITC Great Plains' independence or the benefits they provide as an independent TO has been compromised or reduced as a result of the Fortis and GIC acquisition. On July 16, 2020, the FERC issued an order granting the complaint, setting the revised adder for independent transmission ownership for ITC Great Plains to 25 basis points, and requiring ITC Great Plains to include the revised adder, effective June 11, 2019, in their Formula Rates. In addition, the order directed ITC Great Plains to provide refunds, with interest, for the period from June 11, 2019 through July 16, 2020 within 60 days of the date of the order. On September 15, 2020, the FERC granted an extension to issue refunds until November 19, 2020. On August 17, 2020, ITC Great Plains filed a request for rehearing of the order and on September 17, 2020, the FERC denied the rehearing request. On November 12, 2020, ITC Great Plains filed an appeal of the July 16, 2020 order, and on December 14, 2020, ITC Great Plains filed an appeal of the September 17, 2020 order, both of which were filed in the D.C. Circuit Court. As of December 31, 2019, we had recorded an estimated current regulatory liability of $2 million related to this complaint and during 2020 refunds of $4 million were made to settle the refund liability. We do not expect the final resolution of this proceeding to have a material adverse impact on our consolidated results of operations, cash flows or financial condition.

For each of the years ended December 31, 2019 and 2018, the authorized ROE used by ITC Great Plains was 12.16% and was composed of a base ROE of 10.66% with a 100 basis point adder for independent transmission ownership and a 50 basis point adder for RTO participation. Based on the July 16, 2020 order and as of December 31, 2020, the authorized ROE used by ITC Great Plains was revised to 11.41% and is composed of a base ROE of 10.66% with a 25 basis point adder for independent transmission ownership and a 50 basis point adder for RTO participation.

Rate of Return on Equity Complaints

See "Rate of Return on Equity Complaints" in Note 18 for a discussion of the MISO ROE Complaints.

7. REGULATORY ASSETS AND LIABILITIES

Regulatory Assets

The following table summarizes the regulatory asset balances:

(In millions of USD)	December 31, 2020	December 31, 2019
Regulatory Assets:		
Current:		
Revenue accruals (including accrued interest of $2 and $1 as of December 31, 2020 and 2019, respectively) (a)	$ 44	$ 12
Refund related to the Initial Complaint (including accrued interest of $2 as of December 31, 2020) (b)	8	—
Total current	52	12
Non-current:		
Revenue accruals (including accrued interest of less than $1 and $1 as of December 31, 2020 and 2019, respectively) (a)	19	43
ITCTransmission ADIT deferral (net of accumulated amortization of $54 and $51 as of December 31, 2020 and 2019, respectively)	7	10
METC ADIT deferral (net of accumulated amortization of $33 and $31 as of December 31, 2020 and 2019, respectively)	10	12
METC regulatory deferrals (net of accumulated amortization of $11 and $10 as of December 31, 2020 and 2019, respectively)	4	5
Income taxes recoverable related to AFUDC equity	106	99
ITC Great Plains start-up, development and pre-construction (net of accumulated amortization of $7 and $6 as of December 31, 2020 and 2019, respectively)	6	7
Pensions and postretirement	30	25
Income taxes recoverable related to implementation of the Michigan Corporate Income Tax	6	7
Accrued asset removal costs	24	21
Total non-current	212	229
Total	$ 264	$ 241

(a) Refer to discussion of revenue accruals in Note 6 under “Cost-Based Formula Rates with True-Up Mechanism.” Our Regulated Operating Subsidiaries do not earn a return on the balance of these regulatory assets, but do accrue interest carrying costs, which are subject to rate recovery along with the principal amount of the revenue accrual.

(b) Refer to discussion of the refund liability in Note 18 under “Rate of Return on Equity Complaints.”

ITCTransmission ADIT Deferral

The carrying amount of the ITCTransmission ADIT Deferral is the remaining unamortized balance of the portion of ITCTransmission’s purchase price in excess of fair value of net assets acquired from DTE Energy approved for inclusion in future rates by the FERC. The original amount recorded for this regulatory asset of $61 million is recognized in rates and amortized on a straight-line basis over 20 years beginning March 1, 2003. ITCTransmission includes the remaining unamortized balance of this regulatory asset in rate base. ITCTransmission recorded amortization expense of $3 million annually during 2020, 2019 and 2018, which is included in depreciation and amortization in our consolidated statements of comprehensive income and recovered through ITCTransmission’s cost-based Formula Rate template.

METC ADIT Deferral

The carrying amount of the METC ADIT Deferral is the remaining unamortized balance of the portion of METC's purchase price in excess of the fair value of net assets acquired at the time MTH acquired METC from Consumers Energy approved for inclusion in future rates by the FERC. The original amount approved for recovery recorded for this regulatory asset of $43 million is recognized in rates and amortized on a straight-line basis over 18 years beginning January 1, 2007. METC includes the remaining unamortized balance of this regulatory asset in rate base. METC recorded amortization expense of $2 million annually during 2020, 2019 and 2018, which is included in depreciation and amortization in our consolidated statements of comprehensive income and recovered through METC's cost-based Formula Rate template.

METC Regulatory Deferrals

The carrying amount of the METC Regulatory Deferrals is the amount METC has deferred, as a regulatory asset, of depreciation and related interest expense associated with new transmission assets placed in service from January 1, 2001 through December 31, 2005 that were included on METC's balance sheet at the time MTH acquired METC from Consumers Energy. The original amount recorded for this regulatory asset of $15 million, and approved for inclusion in future rates by the FERC, is recognized in rates and amortized over 20 years beginning January 1, 2007. METC includes the remaining unamortized balance of this regulatory asset in rate base. METC recorded amortization expense of $1 million annually during 2020, 2019 and 2018, which is included in depreciation and amortization in our consolidated statements of comprehensive income and recovered through METC's cost-based Formula Rate template.

Income Taxes Recoverable Related to AFUDC Equity

Accounting standards for income taxes provide that a regulatory asset be recorded if it is probable that a future increase in taxes payable, relating to the book depreciation of AFUDC equity that has been capitalized to property, plant and equipment, will be recovered from customers through future rates. The regulatory asset for the tax effects of AFUDC equity is recovered over the life of the underlying book asset in a manner that is consistent with the depreciation of the AFUDC equity that has been capitalized to property, plant and equipment. This regulatory asset and the related offsetting deferred income tax liabilities do not affect rate base.

ITC Great Plains Start-Up, Development and Pre-Construction

In 2013, ITC Great Plains made a filing with the FERC, under Section 205 of the FPA, to recover start-up, development and pre-construction expenses in future rates. These expenses included certain costs incurred by ITC Great Plains for two regional cost sharing projects in Kansas prior to construction. In March 2015, FERC accepted ITC Great Plains' request to commence amortization of the authorized regulatory assets, subject to refund. In December 2015, the FERC issued an order accepting an uncontested settlement agreement establishing the amounts of the regulatory assets and associated carrying charges to be recovered. ITC Great Plains includes the unamortized balance of these regulatory assets in rate base and will amortize them over a 10-year period, beginning in the second quarter of 2015. The amortization expense is recorded to general and administrative expenses in our consolidated statements of comprehensive income and recovered through ITC Great Plains' cost-based Formula Rate.

Pensions and Postretirement

Accounting standards for defined benefit pension and other postretirement plans for rate-regulated entities allow for amounts that otherwise would have been charged to AOCI to be recorded as a regulatory asset. As the unrecognized amounts recorded to this regulatory asset are recognized, expenses will be recovered from customers in future rates under our cost based Formula Rates. This regulatory asset is not included when determining rate base.

Income Taxes Recoverable Related to Implementation of the Michigan Corporate Income Tax

Under the Michigan Corporate Income Tax, we are taxed at a rate of 6.0% on federal taxable income attributable to our operations in the state of Michigan, subject to certain adjustments. In 2011, due to certain Michigan tax law changes we were required to establish new deferred income tax balances under the Michigan Corporate Income Tax, and the net result was incremental deferred state income tax liabilities at both ITCTransmission and METC. Under our cost-based Formula Rate, the future tax receivable as a result of the tax law change has resulted in the recognition of a regulatory asset, which will be collected from customers for the 23-year period and the 32-year period for ITCTransmission and METC, respectively, beginning in 2016. ITCTransmission and METC include this regulatory asset within deferred taxes for rate-making purposes when determining rate base.

Accrued Asset Removal Costs

The carrying amount of the accrued asset removal costs represents the difference between incurred costs to remove property, plant and equipment and the estimated removal costs included and collected in rates. The portion of depreciation expense included in our depreciation rates related to asset removal costs reduces this regulatory asset and removal costs incurred are added to this regulatory asset. In addition, this regulatory asset has also been adjusted for timing differences between incurred costs to settle legal asset retirement obligations and the recognition of such obligations under the standards set forth by the FASB. Our Regulated Operating Subsidiaries include this item, excluding the cost component related to the recognition of our legal asset retirement obligations under the standards set forth by the FASB, as a reduction to accumulated depreciation for rate-making purposes, when determining rate base.

Regulatory Liabilities

The following table summarizes the regulatory liability balances:

	December 31,	
(In millions of USD)	**2020**	**2019**
Regulatory Liabilities:		
Current:		
Revenue deferrals (including accrued interest of less than $1 and $4 as of December 31, 2020 and 2019, respectively) (a)	$ 1	$ 51
Refund related to the Initial Complaint (including accrued interest of $1 and $6 as of December 31, 2020 and 2019, respectively) (b)	13	70
Refund related to ITC Great Plains incentive adder complaint (c)	—	2
Total current	14	123
Non-current:		
Revenue deferrals (including accrued interest of less than $1 as of December 31, 2020 and 2019) (a)	12	1
Accrued asset removal costs	73	72
Excess state income tax deductions	3	2
Income taxes refundable related to implementation of the TCJA	507	509
Pensions and postretirement	16	—
Other	1	—
Total non-current	612	584
Total	$ 626	$ 707

(a) Refer to discussion of revenue deferrals in Note 6 under “Cost-Based Formula Rates with True-Up Mechanism.” Our Regulated Operating Subsidiaries accrue interest on the true-up amounts which will be refunded through rates along with the principal amount of revenue deferrals in future periods.

(b) Refer to discussion of the refund liability in Note 18 under “Rate of Return on Equity Complaints.”

(c) Refer to discussion of the ITC Great Plains incentive adder in Note 6 under “Incentive Adders for Transmission Rates.”

Accrued Asset Removal Costs

The carrying amount of the accrued asset removal costs represents the difference between incurred costs to remove property, plant and equipment and the estimated removal costs included and collected in rates. The portion of depreciation expense included in our depreciation rates related to asset removal costs is added to this regulatory liability and removal expenditures incurred are charged to this regulatory liability. Our Regulated

Operating Subsidiaries include this item within accumulated depreciation for rate-making purposes and determining rate base.

Excess State Income Tax Deductions

Our Regulated Operating Subsidiaries have taken state income tax deductions associated with property additions that exceed the tax basis of property, and the unrealized income tax benefits resulting from these deductions are expected to be refunded to customers through future rates when the income tax benefits are realized. This regulatory liability is included within deferred taxes for rate-making purposes when determining rate base.

Income Taxes Refundable Related to Implementation of the TCJA

Under the TCJA the income tax rate changed from 35% to 21% effective for tax years beginning after 2017. The Company was required to revalue its deferred tax assets and liabilities at the new federal corporate income tax rate as of the date of the enactment of the TCJA, which resulted in lower net deferred tax liabilities and the establishment of a net regulatory liability for excess deferred taxes at our Regulated Operating Subsidiaries. The excess deferred taxes are generally the result of accelerated federal tax deductions realized by our Regulated Operating Subsidiaries in periods when the U.S. federal corporate income tax rate was 35% and now would be returned to customers in a period where the U.S. federal corporate income tax rate is 21%. As the excess deferred taxes must be returned to customers this net regulatory liability is recognized. For our Regulated Operating Subsidiaries, our deferred taxes are subject to a normalization method of accounting for the excess tax reserves resulting from the change in the federal statutory tax rate which involves the use of ARAM for the determination of the timing of the return of the excess deferred taxes to customers associated with public utility property. In addition, a portion of our excess deferred taxes at our Regulated Operating Subsidiaries are associated with other types of deferred taxes that are not related to public utility property and are subject to amortization. We have elected to amortize these excess deferred taxes using RSGM. During the years ended December 31, 2020 and 2019, we recorded $2 million and $1 million, respectively, of amortization related to the excess deferred taxes under ARAM and RSGM. The net regulatory liability is included within deferred taxes for rate-making purposes when determining rate base.

Pensions and Postretirement

Accounting standards for defined benefit pension and other postretirement plans for rate-regulated entities allow for amounts that otherwise would have been credited to AOCI to be recorded as a regulatory liability. As the unrecognized amounts recorded to this regulatory liability are recognized, amounts will be returned to customers in future rates under our cost based Formula Rates. This regulatory liability is not included when determining rate base.

8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment — net consisted of the following:

	December 31,	
(In millions of USD)	**2020**	**2019**
Property, plant and equipment		
Regulated Operating Subsidiaries:		
Property, plant and equipment in service	$ 10,661	$ 9,973
Construction work in progress	523	375
Capital equipment inventory	103	99
Other	81	51
ITC Holdings and other	14	14
Total	11,382	10,512
Less: Accumulated depreciation and amortization	(2,055)	(1,930)
Property, plant and equipment, net	$ 9,327	$ 8,582

Additions to property, plant and equipment in service and construction work in progress during 2020 and 2019 were due primarily to asset acquisitions and projects to upgrade or replace existing transmission plant and update grid security to improve the reliability of our transmission systems as well as transmission infrastructure to support generator interconnections and investments that provide regional benefits such as our MVPs.

9. GOODWILL AND INTANGIBLE ASSETS

Goodwill

At December 31, 2020 and 2019, we had goodwill balances recorded at ITCTransmission, METC and ITC Midwest of $173 million, $454 million and $323 million, respectively, which resulted from the ITCTransmission and METC acquisitions and ITC Midwest's acquisition of the IP&L transmission assets, respectively.

Intangible Assets

METC has recorded intangible assets with finite lives derived from the portion of regulatory assets recorded on METC's historical FERC financial statements that were not recorded on METC's historical GAAP financial statements. These intangible assets are associated with the METC Regulatory Deferrals and the METC ADIT Deferral as described in Note 7. The carrying amounts of the intangible asset for the METC Regulatory Deferrals and the METC ADIT Deferral were $12 million and $4 million (net of accumulated amortization of $28 million and $15 million), respectively, as of December 31, 2020, and $14 million and $5 million (net of accumulated amortization of $26 million and $14 million), respectively, as of December 31, 2019. The amortization periods for the METC Regulatory Deferrals and the METC ADIT Deferral are 20 and 18, respectively, beginning January 1, 2007. METC earns an equity return on the remaining unamortized balance of both intangible assets and recovers the amortization expense through METC's cost-based Formula Rate template.

ITC Great Plains has recorded intangible assets for payments made by and obligations of ITC Great Plains to certain TOs to acquire rights, which are required under the SPP tariff to designate ITC Great Plains to build, own and operate projects within the SPP region, including three regional cost sharing projects in Kansas. The carrying amount of these intangible assets was $13 million and $14 million (net of accumulated amortization of $3 million and $2 million) as of December 31, 2020 and 2019, respectively. The amortization period for these intangible assets is 50 years, beginning March 31, 2011.

We recognized $4 million, $3 million, and $4 million of amortization expense of our intangible assets during the years ended December 31, 2020, 2019 and 2018, respectively, recorded in depreciation and amortization on the consolidated statements of comprehensive income. We expect the annual amortization of our intangible assets that have been recorded as of December 31, 2020 to be as follows:

(In millions of USD)	
2021	$ 3
2022	3
2023	4
2024	3
2025	3
2026 and thereafter	13
Total	$ 29

10. DEBT

Amounts of outstanding debt were classified as debt maturing within one year and long-term debt in the consolidated statements of financial position as follows:

	December 31,	
(In millions of USD)	2020	2019
ITC Holdings 6.375% Senior Notes, due September 30, 2036	$ 200	$ 200
ITC Holdings 4.05% Senior Notes, due July 1, 2023	250	250
ITC Holdings 3.65% Senior Notes, due June 15, 2024	400	400
ITC Holdings 5.30% Senior Notes, due July 1, 2043	300	300
ITC Holdings 3.25% Notes, due June 30, 2026	400	400
ITC Holdings 2.70% Senior Notes, due November 15, 2022	500	500
ITC Holdings 3.35% Senior Notes, due November 15, 2027	500	500
ITC Holdings 2.95% Senior Notes, due May 14, 2030	700	—
ITC Holdings Term Loan Credit Agreement, due June 11, 2021	—	200
ITC Holdings Revolving Credit Agreement, due October 21, 2023	37	34
ITC Holdings Commercial Paper Program (a)	67	200
ITCTransmission 6.125% First Mortgage Bonds, Series C, due March 31, 2036	100	100
ITCTransmission 4.625% First Mortgage Bonds, Series E, due August 15, 2043	285	285
ITCTransmission 4.27% First Mortgage Bonds, Series F, due June 10, 2044	100	100
ITCTransmission 4.00% First Mortgage Bonds, Series G, due March 30, 2053	225	225
ITCTransmission 3.30% First Mortgage Bonds, Series H, due August 28, 2049	75	75
ITCTransmission Revolving Credit Agreement, due October 21, 2023	33	24
METC 5.64% Senior Secured Notes, due May 6, 2040	50	50
METC 3.98% Senior Secured Notes, due October 26, 2042	75	75
METC 4.19% Senior Secured Notes, due December 15, 2044	150	150
METC 3.90% Senior Secured Notes, due April 26, 2046	200	200
METC 4.55% Senior Secured Notes, due January 15, 2049	50	50
METC 4.65% Senior Secured Notes, due July 10, 2049	50	50
METC 3.02% Senior Secured Notes, due October 14, 2055	150	—
METC Revolving Credit Agreement, due October 21, 2023	20	79
ITC Midwest 6.15% First Mortgage Bonds, Series A, due January 31, 2038	175	175
ITC Midwest 7.27% First Mortgage Bonds, Series C, due December 22, 2020 (a)	—	35
ITC Midwest 4.60% First Mortgage Bonds, Series D, due December 17, 2024	75	75
ITC Midwest 3.50% First Mortgage Bonds, Series E, due January 19, 2027	100	100
ITC Midwest 4.09% First Mortgage Bonds, Series F, due April 30, 2043	100	100
ITC Midwest 3.83% First Mortgage Bonds, Series G, due April 7, 2055	225	225
ITC Midwest 4.16% First Mortgage Bonds, Series H, due April 18, 2047	200	200
ITC Midwest 4.32% First Mortgage Bonds, Series I, due November 1, 2051	175	175
ITC Midwest 3.13% First Mortgage Bonds, Series J, due July 15, 2051	180	—
ITC Midwest Revolving Credit Agreement, due October 21, 2023	75	130
ITC Great Plains 4.16% First Mortgage Bonds, Series A, due November 26, 2044	150	150
ITC Great Plains Revolving Credit Agreement, due October 21, 2023	33	32
Total principal	6,405	5,844
Unamortized deferred financing fees and discount	(43)	(37)
Total debt	$ 6,362	$ 5,807

(a) As of December 31, 2020 and 2019 there was $67 million and $235 million, respectively, of debt included within debt maturing within one year in the consolidated statements of financial position.

The annual maturities of debt as of December 31, 2020 are as follows:

(In millions of USD)		
2021	$	67
2022		500
2023		448
2024		475
2025		—
2026 and thereafter		4,915
Total	$	6,405

ITC Holdings

Senior Unsecured Notes

On May 14, 2020, ITC Holdings completed the private offering of $700 million aggregate principal amount of unsecured 2.95% Senior Notes, due May 14, 2030. The net proceeds from this offering were used to repay the amount outstanding under ITC Holdings' $400 million term loan credit agreement, to repay $122 million under ITC Holdings' revolving credit agreement, and to repay $92 million under ITC Holdings' commercial paper program, with remaining proceeds to be used for general corporate purposes. These Senior Notes were issued under ITC Holdings' indenture, dated April 18, 2013.

Term Loan Credit Agreement

On June 12, 2019, ITC Holdings entered into an unsecured, unguaranteed $400 million term loan credit agreement with a maturity date of June 11, 2021, under which ITC Holdings borrowed $200 million. The proceeds were used for the early redemption of the $200 million 5.50% Senior Notes due January 15, 2020. In January 2020, ITC Holdings drew upon the remaining $200 million under the term loan credit agreement to repay outstanding commercial paper balances. These borrowings were repaid in full in May 2020 from the proceeds of the ITC Holdings Senior Notes issued on May 14, 2020. The weighted-average interest rate throughout the life of the loan was 2.27%.

Commercial Paper Program

ITC Holdings has an ongoing commercial paper program for the issuance and sale of unsecured commercial paper in an aggregate amount not to exceed $400 million outstanding at any one time. As of December 31, 2020, ITC Holdings had $67 million of commercial paper, net of discount, issued and outstanding under the program, with a weighted-average interest rate of 0.3% and weighted average remaining days to maturity of 14 days. The amount outstanding as of December 31, 2020 was classified as debt maturing within one year in the consolidated statements of financial position. As of December 31, 2019, ITC Holdings had $200 million of commercial paper issued and outstanding.

ITCTransmission

First Mortgage Bonds

On August 28, 2019, ITCTransmission issued $75 million aggregate principal amount of 3.30% First Mortgage Bonds, due August 28, 2049. The proceeds were used to repay existing indebtedness under the revolving credit agreement and will also be used to partially fund capital expenditures and for general corporate purposes. All of ITCTransmission's First Mortgage Bonds are issued under its First Mortgage and Deed of Trust and secured by a first mortgage lien on substantially all of its real property and tangible personal property.

METC

Senior Secured Notes

On October 14, 2020, METC issued $150 million of 3.02% Senior Secured Notes, due October 14, 2055. The proceeds from the issuance were used to repay amounts outstanding under METC's term loan credit agreement, to repay borrowings under its revolving credit agreement, to partially fund capital expenditures and for general corporate purposes. All of METC's Senior Secured Notes are issued under its first mortgage indenture and secured by a first mortgage lien on substantially all of its real property and tangible personal property.

On January 15, 2019, METC issued $50 million of 4.55% Senior Secured Notes, due January 15, 2049. On July 10, 2019, METC issued an additional $50 million of Senior Secured Notes at 4.65% with terms and conditions identical to those of the 4.55% Senior Secured Notes except the interest rate which includes a 10 basis point premium and the due date which is 30 years from the date of the issuance. The proceeds from both issuances were used to repay borrowings under the METC revolving credit agreement, to partially fund capital expenditures and for general corporate purposes. All of METC's Senior Secured Notes are issued under its first mortgage indenture and secured by a first mortgage lien on substantially all of its real property and tangible personal property.

Term Loan Credit Agreement

On January 23, 2020, METC entered into an unsecured, unguaranteed term loan credit agreement, due January 23, 2021, under which METC borrowed the maximum of $75 million available under the agreement. The proceeds were used for general corporate purposes, primarily the repayment of borrowings under the METC revolving credit agreement. This borrowing was repaid in full on October 14, 2020 from the proceeds of the METC Senior Secured Notes issued on October 14, 2020. The weighted-average interest rate throughout the life of the loan was 1.08%.

ITC Midwest

First Mortgage Bonds

On July 15, 2020, ITC Midwest issued an aggregate of $180 million of 3.13% First Mortgage Bonds due July 15, 2051. The proceeds were used to partially repay existing indebtedness under the ITC Midwest revolving credit agreement, partially fund capital expenditures and for general corporate purposes. ITC Midwest's First Mortgage Bonds were issued under its first mortgage and deed of trust and secured by a first mortgage lien on substantially all of its real property and tangible personal property.

Derivative Instruments and Hedging Activities

In May 2020, we terminated $450 million of 5-year interest rate swap contracts that managed the interest rate risk associated with the ITC Holdings $700 million Senior Notes with a maturity date of May 14, 2030. A summary of the terminated interest rate swaps is provided below:

Interest Rate Swaps (in millions of USD, except percentages)	Notional Amount	Weighted Average Fixed Rate of Interest Rate Swaps	Comparable Reference Rate of Notes	Loss on Derivatives	Settlement Date
5-year interest rate swaps	$ 450	1.41 %	0.38%	$ 23	May 2020

The interest rate swaps qualified for cash flow hedge accounting treatment and the cumulative pre-tax loss of $23 million was recognized in May 2020 for the effective portion of the hedges and recorded net of tax in AOCI. This amount is being amortized as a component of interest expense over the initial five years of the term of the related debt. Consistent with our accounting policy, the swap settlement payment was recognized within cash flows from financing activities in the consolidated statements of cash flows. At December 31, 2020, ITC Holdings did not have any interest rate swaps outstanding. As of December 31, 2019, ITC Holdings had $200 million of interest rate swaps outstanding.

Revolving Credit Agreements

On January 10, 2020, ITC Holdings, ITCTransmission, METC, ITC Midwest and ITC Great Plains amended and restated their respective revolving credit agreements each dated October 23, 2017. The amendments extend the maturity date of the revolving credit agreements from October 2022 to October 2023. The determination of the applicable interest rates and commitment fee rates in the new agreements is consistent with the previous agreements and remain subject to adjustment based on the borrower's credit rating. At December 31, 2020, ITC Holdings and certain of its Regulated Operating Subsidiaries had the following unsecured revolving credit facilities available:

(In millions of USD, except percentages)	Total Available Capacity	Outstanding Balance (a)	Unused Capacity	Weighted Average Interest Rate on Outstanding Balance (b)	Commitment Fee Rate (c)
ITC Holdings	$ 400	$ 37	$ 363 (d)	1.4%	0.175 %
ITCTransmission	100	33	67	1.1%	0.10 %
METC	100	20	80	1.1%	0.10 %
ITC Midwest	225	75	150	1.1%	0.10 %
ITC Great Plains	75	33	42	1.1%	0.10 %
Total	$ 900	$ 198	$ 702		

(a) Included within long-term debt in the consolidated statements of financial position.

(b) Interest charged on borrowings depends on the variable rate structure we elected at the time of each borrowing.

(c) Calculation based on the average daily unused commitments, subject to adjustment based on the borrower's credit rating.

(d) ITC Holdings' revolving credit agreement may be used for general corporate purposes, including to repay commercial paper issued pursuant to the commercial paper program described above, if necessary. While outstanding commercial paper does not reduce available capacity under ITC Holdings' revolving credit agreement, the unused capacity under this agreement adjusted for the commercial paper outstanding was $296 million as of December 31, 2020.

11. INCOME TAXES

Our effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

(In millions of USD)	Year Ended December 31, 2020	2019	2018
Income tax expense at federal statutory rate (a)	$ 114	$ 118	$ 93
State income taxes (net of federal benefit) (b)	28	22	31
AFUDC equity	(4)	(5)	(6)
Other, net	(2)	(3)	(7)
Total income tax provision	$ 136	$ 132	$ 111

(a) The federal statutory rate is 21% for 2020, 2019 and 2018.

(b) Amounts for the years ended December 31, 2020, 2019 and 2018 include $2 million, $1 million and $6 million, respectively, related to the remeasurement of Iowa NOLs due to the rate change from 12.0% to 9.8% effective January 1, 2021.

Components of the income tax provision were as follows:

(In millions of USD)	Year Ended December 31, 2020	2019	2018
Current income tax (benefit) expense	$ (2)	$ (3)	$ 4
Deferred income tax expense	138	135	107
Total income tax provision	$ 136	$ 132	$ 111

For the years ended December 31, 2020, 2019 and 2018, our effective tax rates were 25.0%, 23.6% and 25.2%, respectively.

Deferred income tax assets (liabilities) consisted of the following:

(In millions of USD)	December 31, 2020	2019
Property, plant and equipment	$ (1,156)	$ (1,071)
Federal income tax NOLs and other credits	85	117
METC regulatory deferral (a)	(4)	(5)
Acquisition adjustments — ADIT deferrals (a)	(5)	(7)
Goodwill	(139)	(133)
Refund liabilities (a)	—	19
Regulatory liability gross up — TCJA	134	134
Pension and postretirement liabilities	20	18
State income tax NOLs (net of federal benefit)	58	52
True-up adjustment principal & interest	(14)	(1)
Other, net	8	4
Net deferred tax liabilities	$ (1,013)	$ (873)
Gross deferred income tax liabilities	$ (1,333)	$ (1,233)
Gross deferred income tax assets	320	360
Net deferred tax liabilities	$ (1,013)	$ (873)

(a) Deferred income tax assets for refund liabilities are related to the Initial Complaint and the ITC Great Plains incentive adder complaint. See Note 7 for additional details regarding these matters.

We have federal income tax NOLs as of December 31, 2020. We expect to use our NOLs prior to their expirations starting in 2036. We also have state income tax NOLs as of December 31, 2020, all of which we expect to use prior to their expiration starting in 2022.

12. RETIREMENT BENEFITS AND ASSETS HELD IN TRUST

Pension and Postretirement Plan Benefits

We have a qualified defined benefit pension plan ("retirement plan") for eligible employees, comprised of a traditional final average pay plan and a cash balance plan. The traditional final average pay plan is noncontributory, covers select employees, and provides retirement benefits based on years of benefit service, average final compensation, and age at retirement. The cash balance plan is also noncontributory, covers substantially all employees, and provides retirement benefits based on eligible compensation and interest credits. Our funding practice for the retirement plan is generally to fund the annual net pension cost, though we may contribute additional amounts as necessary to meet the minimum funding requirements of the Employee Retirement Income Security Act of 1974, or as we deem appropriate. We made contributions of $4 million to the retirement plan in each of 2020, 2019, and 2018. We expect to contribute $4 million to the retirement plan in 2021.

We also have two supplemental nonqualified, noncontributory, defined benefit pension plans for selected management employees (the “supplemental benefit plans” and collectively with the retirement plan, the “pension plans”). The supplemental benefit plans provide for benefits that supplement those provided by the retirement plan. The obligations under these supplemental benefit plans are included in the pension benefit obligation calculations below. The investments held in trust for the supplemental benefit plans of $56 million and $54 million at December 31, 2020 and 2019, respectively, are not included in the plan asset amounts presented throughout this footnote, but are included in other assets on our consolidated statements of financial position. For the years ended December 31, 2020, 2019, and 2018, we contributed $3 million, $1 million, and $3 million, respectively, to these supplemental benefit plans.

We provide certain postretirement health care, dental, and life insurance benefits for eligible employees (the “postretirement benefit plan”). We contributed $10 million, $9 million, and $9 million to the postretirement benefit plan in 2020, 2019, and 2018, respectively. We expect to contribute $11 million to the postretirement benefit plan in 2021.

Net periodic benefit costs by component for the pension plans and postretirement benefit plan were as follows:

	Pension Plans			Postretirement Benefit Plan		
	Years Ended December 31,			Years Ended December 31,		
(In millions of USD)	2020	2019	2018	2020	2019	2018
Service cost	$ 8	$ 7	$ 7	$ 11	$ 9	$ 10
Interest cost	4	5	4	4	4	3
Expected return on plan assets	(6)	(5)	(5)	(5)	(4)	(3)
Amortization of unrecognized loss	1	1	1	—	—	—
Net benefit cost	$ 7	$ 8	$ 7	$ 10	$ 9	$ 10

The following table reconciles the obligations, assets, and funded status of the pension plans and postretirement benefit plan as well as the presentation of the funded status of the plans in the consolidated statements of financial position:

	Pension Plans		Postretirement Benefit Plan	
	December 31,		December 31,	
(In millions of USD)	2020	2019	2020	2019
Change in Benefit Obligation:				
Beginning projected benefit obligation	$ (141)	$ (123)	$ (113)	$ (90)
Service cost	(8)	(7)	(11)	(9)
Interest cost	(4)	(5)	(4)	(4)
Plan amendments	—	—	2	—
Actuarial net gain/(loss)	(16)	(12)	3	(11)
Benefits paid	7	6	1	1
Ending projected benefit obligation	(162)	(141)	(122)	(113)
Change in Plan Assets:				
Beginning plan assets at fair value	91	73	95	72
Actual return on plan assets	15	16	16	15
Employer contributions	4	4	10	9
Benefits paid	(3)	(2)	(1)	(1)
Ending plan assets at fair value	107	91	120	95
Funded status, underfunded	$ (55)	$ (50)	$ (2)	$ (18)
Accumulated benefit obligation:				
Retirement plan	$ (95)	$ (78)	N/A	N/A
Supplemental benefit plans	(60)	(57)	N/A	N/A
Total accumulated benefit obligation	$ (155)	$ (135)	$ —	$ —
Amounts recorded as:				
Funded Status:				
Accrued pension and postretirement liabilities	$ (57)	$ (55)	$ (2)	$ (18)
Other non-current assets	6	9	N/A	N/A
Other current liabilities	(4)	(4)	N/A	N/A
Total	$ (55)	$ (50)	$ (2)	$ (18)
Unrecognized Amounts in Non-current Regulatory Assets/(Liabilities):				
Net actuarial loss/(gain)	$ 30	$ 24	$ (14)	$ 1
Net prior service cost/(credit)	—	—	(2)	—
Total	$ 30	$ 24	$ (16)	$ 1

The unrecognized amounts that otherwise would have been charged and/or credited to AOCI in accordance with the GAAP guidance on accounting for retirement benefits are recorded as a regulatory asset or regulatory liability on our consolidated statements of financial position, as discussed in Note 7. The amounts recorded as a regulatory asset or regulatory liability represent a net periodic benefit cost or credit to be recognized in our operating income in future periods. Our measurement of the accumulated benefit obligation for the postretirement benefit plan as of December 31, 2020 and 2019 does not reflect the potential receipt of any subsidies under the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

The net actuarial losses for the year ended December 31, 2019 within the change in benefit obligation for both the Pension Plans and Postretirement Benefit Plan are primarily the result of decreases in the discount rates.

The net actuarial loss for the year ended December 31, 2020 within the change in benefit obligation for the Pension Plans is primarily the result of decreases in the discount rates. The net actuarial gain for the year ended December 31, 2020 within the change in benefit obligation for the Postretirement Benefit Plan was driven primarily by per capita experience gains as well as other actuarial gains, partially offset by a decrease in the discount rate.

The combined projected benefit obligation and fair value of plan assets for those plans in which the projected benefit obligation is in excess of the fair value of plan assets are as follows:

	Pension Plans	
	December 31,	
(In millions of USD)	2020	2019
Projected benefit obligation	$ (61)	$ (59)
Fair value of plan assets (a)	—	—

(a) The investments held in trust for our supplemental benefit plans are not included in the plan asset amounts presented herein, but are included in Other Assets on our consolidated statements of financial position.

The combined accumulated benefit obligation and fair value of plan assets for those plans in which the accumulated benefit obligation is in excess of the fair value of plan assets are as follows:

	Pension Plans	
	December 31,	
(In millions of USD)	2020	2019
Accumulated benefit obligation	$ (60)	$ (57)
Fair value of plan assets (a)	—	—

(a) The investments held in trust for our supplemental benefit plans are not included in the plan asset amounts presented herein, but are included in Other Assets on our consolidated statements of financial position.

Actuarial assumptions used to determine the benefit obligations for the pension plans and postretirement benefit plan are as follows:

	Pension Plans			Postretirement Benefit Plan		
	December 31,			December 31,		
	2020	2019	2018	2020	2019	2018
Weighted average discount rate	2.49%	3.27%	4.28%	2.94%	3.61%	4.47%
Weighted average interest crediting rate	4.00%	4.00%	4.50%	N/A	N/A	N/A
Annual rate of salary increases	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate	N/A	N/A	N/A	6.00%	6.25%	6.50%
Ultimate health care cost trend rate	N/A	N/A	N/A	5.00%	5.00%	5.00%
Year that the ultimate trend rate is reached	N/A	N/A	N/A	2025	2025	2025
Annual rate of increase in dental benefit costs	N/A	N/A	N/A	4.50%	4.50%	4.50%

Actuarial assumptions used to determine the benefit cost for the pension plans and postretirement benefit plan are as follows:

	Pension Plans			Postretirement Benefit Plan		
	Years Ended December 31,			Years Ended December 31,		
	2020	2019	2018	2020	2019	2018
Weighted average discount rate — service cost	3.47%	4.42%	3.70%	3.80%	4.58%	3.80%
Weighted average discount rate — interest cost	2.91%	3.99%	3.26%	3.30%	4.28%	3.58%
Weighted average interest crediting rate	4.00%	4.50%	4.50%	N/A	N/A	N/A
Annual rate of salary increases	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate	N/A	N/A	N/A	6.25%	6.50%	6.75%
Ultimate health care cost trend rate	N/A	N/A	N/A	5.00%	5.00%	5.00%
Year that the ultimate trend rate is reached	N/A	N/A	N/A	2025	2025	2025
Expected long-term rate of return on plan assets	6.00%	6.60%	6.40%	4.50%	5.00%	4.90%

At December 31, 2020, the projected benefit payments for the pension plans and postretirement benefit plan calculated using the same assumptions as those used to calculate the benefit obligations described above are as follows:

(In millions of USD)	Pension Plans	Postretirement Benefit Plan
2021	$ 7	$ 2
2022	8	2
2023	9	2
2024	9	2
2025	10	3
2026 through 2030	59	21

Investment Objectives and Fair Value Measurement

The general investment objectives of the retirement plan and postretirement benefit plan include maximizing the return within reasonable and prudent levels of risk and controlling administrative and management costs. Investment decisions are made by our retirement benefits board as delegated by our board of directors. Equity investments may include various types of U.S. and international equity securities, such as large-cap, mid-cap, and small-cap stocks. Fixed income investments may include cash and short-term instruments, U.S. Government securities, corporate bonds, mortgages, and other fixed income investments. No investments are prohibited for use in the retirement plan or postretirement benefit plan, including derivatives, but our exposure to derivatives currently is not material. We intend that the long-term capital growth of the retirement and postretirement benefit plans, together with employer contributions, will provide for the payment of the benefit obligations.

As of December 31, 2020 and 2019, the plan assets of the retirement plan and postretirement benefit plan consisted of the following assets by category:

	Target Allocation	Pension Plans		Postretirement Benefit Plan	
Asset Category	2020	2020	2019	2020	2019
Fixed income securities	50 %	50 %	50 %	50 %	50 %
Equity securities	50 %	50 %	50 %	50 %	50 %
Total	100 %	100 %	100 %	100 %	100 %

We determine our expected long-term rate of return on plan assets based on the current and expected target allocations of the retirement plan and postretirement benefit plan investments and considering historical and expected long-term rates of return on comparable fixed income investments and equity investments.

The measurement of fair value is based on a three-tier hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs, such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore, requiring an entity to develop its own assumptions. Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one fair value level to another. In such instances, the transfer is reported at the beginning of the reporting period. For the years ended December 31, 2020 and 2019, there were no transfers between levels.

For the years ended December 31, 2020 and 2019, the fair value of retirement plan and postretirement benefit plan assets measured on a recurring basis at the Level 1 tier were as follows:

	Pension Plans		Postretirement Benefit Plan	
	December 31,		December 31,	
(In millions of USD)	2020	2019	2020	2019
Mutual funds — U.S. equity securities	$ 43	$ 36	$ 57	$ 45
Mutual funds — international equity securities	11	9	3	2
Mutual funds — fixed income securities	53	46	60	48
Total	$ 107	$ 91	$ 120	$ 95

The mutual funds consist primarily of publicly traded mutual funds and are recorded at fair value based on observable trades for identical securities in an active market.

Defined Contribution Plan

We also sponsor a defined contribution retirement savings plan. Participation in this plan is available to substantially all employees. We match employee contributions up to certain predefined limits based upon eligible compensation and the employee's contribution rate. The cost of this plan was $6 million in 2020 and $5 million in each of 2019 and 2018.

13. FAIR VALUE MEASUREMENTS

The measurement of fair value is based on a three-tier hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one fair value level to another. In such instances, the transfer is reported at the beginning of the reporting period. For the years ended December 31, 2020 and 2019, there were no transfers between levels.

Our assets measured at fair value subject to the three-tier hierarchy at December 31, 2020, were as follows:

	Fair Value Measurements at Reporting Date Using		
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
(in millions of USD)	(Level 1)	(Level 2)	(Level 3)
Financial assets measured on a recurring basis:			
Cash equivalents	$ 1	$ —	$ —
Mutual funds — fixed income securities	52	—	$ —
Mutual funds — equity securities	10	—	—
Total	$ 63	$ —	$ —

Our assets measured at fair value subject to the three-tier hierarchy at December 31, 2019, were as follows:

	Fair Value Measurements at Reporting Date Using		
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
(in millions of USD)	(Level 1)	(Level 2)	(Level 3)
Financial assets measured on a recurring basis:			
Mutual funds — fixed income securities	$ 50	$ —	$ —
Mutual funds — equity securities	8	—	—
Interest rate swap derivatives	—	3	—
Total	$ 58	$ 3	$ —

As of December 31, 2020 and 2019, we held certain assets that are required to be measured at fair value on a recurring basis. The assets included in the table consist of investments recorded within cash and cash equivalents and other long-term assets, including investments held in a trust associated with our supplemental benefit plans described in Note 12. The mutual funds we own are publicly traded and are recorded at fair value based on observable trades for identical securities in an active market. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value. Gains and losses for all mutual fund investments are recorded in other operating income and expense.

As of December 31, 2019, the assets related to derivatives consisted of interest rate swaps discussed in Note 10. The fair value of our interest rate swap derivatives is determined based on a DCF method using LIBOR swap rates, which are observable at commonly quoted intervals.

We also held non-financial assets that are required to be measured at fair value on a non-recurring basis. These consist of goodwill and intangible assets. We did not record any impairment charges on long-lived assets and no other significant events occurred requiring non-financial assets and liabilities to be measured at fair value (subsequent to initial recognition) during the years ended December 31, 2020 and 2019. Refer to Note 9 for additional information on our goodwill and intangible assets.

Fair Value of Financial Assets and Liabilities

Fixed Rate Debt

Based on the borrowing rates obtained from third party lending institutions currently available for bank loans with similar terms and average maturities from active markets, the fair value of our consolidated long-term debt and debt maturing within one year, excluding revolving and term loan credit agreements and commercial paper, was $7,119 million and $5,672 million at December 31, 2020 and 2019, respectively. These fair values represent Level 2 under the three-tier hierarchy described above. The total book value of our consolidated long-term debt and debt maturing within one year, net of discount and deferred financing fees and excluding revolving and term loan credit agreements and commercial paper, was $6,097 million and $5,108 million at December 31, 2020 and 2019, respectively.

Revolving and Term Loan Credit Agreements

At December 31, 2020 and 2019, we had a consolidated total of $198 million and $499 million, respectively, outstanding under our revolving and term loan credit agreements, which are variable rate loans. The fair value of these loans approximates book value based on the borrowing rates currently available for variable rate loans obtained from third party lending institutions. These fair values represent Level 2 under the three-tier hierarchy described above.

Other Financial Instruments

The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents, special deposits and commercial paper, approximates their fair value due to the short-term nature of these instruments.

14. STOCKHOLDER'S EQUITY

Accumulated Other Comprehensive Income

The following table provides the components of changes in AOCI:

(In millions of USD)	Year Ended December 31, 2020	2019	2018
Balance at the beginning of period	$ 7	$ 4	$ 2
Reclassification of deferred tax effects on interest rate cash flow hedges stranded in AOCI, subject to the TCJA, into retained earnings	—	—	1
Other Comprehensive Income			
Derivative Instruments			
Reclassification of net loss relating to interest rate cash flow hedges from AOCI to earnings (net of tax of $1 for the year ended December 31, 2020 and less than $1 for each of the years ended December 31, 2019 and 2018) (a)	3	1	1
(Loss) gain on interest rate swaps relating to interest rate cash flow hedges (net of tax of $8 and $1 for the years ended December 31, 2020 and 2019, respectively)	(18)	2	—
Total other comprehensive (loss) income, net of tax	(15)	3	1
Balance at the end of period	$ (8)	$ 7	$ 4

(a) The reclassification of the net loss relating to interest rate cash flow hedges is reported in interest expense on a pre-tax basis.

The amount of net loss relating to interest rate cash flow hedges to be reclassified from AOCI to earnings for the 12-month period ending December 31, 2021 is expected to be approximately $4 million (net of tax of less than $2 million). The reclassification is reported in interest expense on a pre-tax basis.

15. SHARE-BASED COMPENSATION AND EMPLOYEE SHARE PURCHASE PLAN

We recorded share-based compensation costs as follows:

(In millions of USD)	Year Ended December 31, 2020	2019	2018
Operation and maintenance expenses	$ 2	$ 2	$ 1
General and administrative expenses	23	30	7
Amounts capitalized to property, plant and equipment	7	8	3
Total share-based compensation costs	$ 32	$ 40	$ 11
Total tax benefit recognized in the consolidated statements of comprehensive income	$ 8	$ 8	$ 4

Long-Term Incentive Plans

Under our long-term incentive plans, we may grant long-term incentive awards of PBUs and SBUs to employees, including executive officers, of ITC Holdings and its subsidiaries. Generally, each PBU and SBU granted will be valued based on one share of Fortis common stock traded on the Toronto Stock Exchange, converted to U.S. dollars and settled only in cash. However, certain SBUs granted to the executives may settle in cash, 100% Fortis common stock, or 50% cash and 50% Fortis common stock depending on executives' settlement elections and whether certain share ownership requirements are met. PBUs and SBUs that are granted pursuant to our long-term incentive plans generally vest on either the third December 31st or January 1st following the grant date, provided the service and performance criteria, as applicable, are satisfied, and will be settled during the subsequent quarter. However, certain awards may vest over a shorter period or on the grant date if certain retirement eligibility criteria are met. The granted awards and related dividend equivalents have no shareholder rights.

Performance-Based Units

The PBUs are classified as liability awards based on the cash settlement feature. The PBUs are measured at fair value at the end of each reporting period, which will fluctuate based on the price of Fortis common stock and the level of achievement of the financial performance criteria, including a market condition and a performance condition. The payout may range from 0% - 200% of the target award, depending on actual performance relative to the performance criteria. The PBUs earn dividend equivalents which are also re-measured consistent with the target award and settled in cash at the end of the vesting period.

The following table shows the changes in PBUs during the year ended December 31, 2020:

	Number of Performance Based Units
PBUs at December 31, 2019	976,228
Granted	319,440
Vested and paid out	(335,619)
Forfeited	(59,098)
PBUs at December 31, 2020	900,951

The following table presents the classification in the consolidated statements of financial position of obligations related to outstanding PBUs not yet settled:

	December 31,	
(In millions of USD)	**2020**	**2019**
Accrued compensation	$ 20	$ 17
Other long-term liabilities	22	19
Total	$ 42	$ 36

The aggregate fair value of PBUs as of December 31, 2020 and 2019 was $59 million and $54 million, respectively. At December 31, 2020, $17 million of total unrecognized compensation cost related to PBUs not yet vested is expected to be recognized over the remaining weighted-average period of 1.6 years.

Service-Based Units

The SBUs are classified as liability awards based on the possibility of cash settlement. The SBUs are measured at fair value at the end of each reporting period, which will fluctuate based on the price of Fortis common stock. The SBUs earn dividend equivalents which are also re-measured based on the price of Fortis common stock and settled in cash at the end of the vesting period.

The following table shows the changes in SBUs during the year ended December 31, 2020:

	Number of Service Based Units
SBUs at December 31, 2019	745,250
Granted	246,714
Vested and paid out	(266,918)
Forfeited	(37,336)
SBUs at December 31, 2020	687,710

The following table presents the classification in the consolidated statements of financial position of obligations related to outstanding SBUs not yet settled:

(In millions of USD)	December 31, 2020	December 31, 2019
Accrued compensation	$ 9	$ 10
Other long-term liabilities	10	10
Total	$ 19	$ 20

The aggregate fair value of SBUs as of December 31, 2020 and 2019 was $28 million and $30 million, respectively. At December 31, 2020, $9 million of the total unrecognized compensation cost related to SBUs not yet vested is expected to be recognized over the remaining weighted-average period of 1.6 years.

Employee Share Purchase Plan

ITC employees are permitted to purchase common shares of Fortis stock under the Fortis ESPP. ITC Holdings also makes contributions as additional compensation to participating employees' ESPP accounts. The cost of ITC Holdings' contribution for the years ended December 31, 2020, 2019, and 2018 was less than $1 million, respectively.

16. JOINTLY OWNED UTILITY PLANT/COORDINATED SERVICES

Certain of our Regulated Operating Subsidiaries have agreements with other utilities for the joint ownership of substation assets and transmission lines as discussed in Note 3. We have investments in jointly owned utility assets as shown in the table below as of December 31, 2020:

(In millions of USD)	Net Investments (a) Substations	Net Investments (a) Lines
ITCTransmission (b)	$ —	$ 29
METC (c)	17	41
ITC Midwest (d)	44	41
ITC Great Plains (e)	10	23
Total	$ 71	$ 134

(a) Amount represents our investment in jointly held plant, which has been reduced by the ownership interest amounts of other parties.

(b) ITCTransmission has joint ownership in two 345 kV transmission lines with a municipal power agency that has a 50.4% ownership interest in the transmission lines. An Ownership and Operating Agreement with the municipal power agency provides ITCTransmission with authority for construction of capital improvements and for the operation and management of the transmission lines. The municipal power agency is responsible for the capital and operation and maintenance costs allocable to their ownership interest.

(c) METC has joint ownership in several assets within various substations with Consumers Energy, other municipal distribution systems and other generators. The rights, responsibilities and obligations for these jointly owned assets are documented in the DT Interconnection Agreement with Consumers Energy and in numerous interconnection facilities agreements with various municipalities and other generators. In addition, other municipal power agencies and cooperatives have an ownership interest in several METC 345 kV transmission lines. This ownership entitles these municipal power agencies and cooperatives to approximately 608 MW of network transmission service from the METC transmission system. As of December 31, 2020, METC's ownership percentages for jointly owned substation facilities and lines ranged from less than 1.0% to 92.0% and 1.0% to 41.9%, respectively.

(d) ITC Midwest has joint ownership in several substations and transmission lines with various parties. ITC Midwest's ownership percentages for jointly owned substation facilities and lines ranged from 28.0% to 80.0% and 11.0% to 80.0%, respectively, as of December 31, 2020.

(e) ITC Great Plains has joint ownership in a transmission project with an electric cooperative. ITC Great Plains is responsible for construction and operation of the project and the electric cooperative is responsible for their ownership percentage of capital and operation and maintenance costs. As of December 31, 2020, ITC Great Plains' ownership percentage in the project was 51.0%.

17. RELATED PARTY TRANSACTIONS

Intercompany Receivables and Payables

ITC Holdings may incur charges from Fortis and other subsidiaries of Fortis that are not subsidiaries of ITC Holdings for general corporate expenses incurred. In addition, ITC Holdings may perform additional services for, or receive additional services from, Fortis and such subsidiaries. These transactions are in the normal course of business and payments for these services are settled through accounts receivable and accounts payable, as necessary. We had intercompany receivables from Fortis and such subsidiaries of less than $1 million at December 31, 2020 and December 31, 2019 and intercompany payables to Fortis and such subsidiaries of less than $1 million at December 31, 2020 and December 31, 2019.

Related party charges for corporate expenses from Fortis and such subsidiaries are recorded in general and administrative expense. ITC Holdings had such expense for the years ended December 31, 2020 and 2019 of $10 million and for the year ended December 31, 2018 of $8 million. Related party billings for services to Fortis and other subsidiaries recorded as an offset to general and administrative expenses for ITC Holdings were $2 million for the year ended December 31, 2020 and less than $1 million for the years ended December 31, 2019 and 2018.

Dividends

We paid dividends of $330 million, $250 million and $200 million during the years ended December 31, 2020, 2019 and 2018, respectively, to ITC Investment Holdings. ITC Holdings also paid dividends of $58 million to ITC Investment Holdings in January 2021.

Transfer of Membership Interests

In February 2021, we transferred our membership interests in certain wholly-owned development entities to our parent company, ITC Investment Holdings. The transfer was accounted for at book value as a non-reciprocal transfer of value. There was no gain or loss recognized on the transfer. The transfer will not have a material impact on our consolidated results of operations, cash flows or financial condition.

Intercompany Tax Sharing Agreement

We are organized as a corporation for tax purposes and subject to a tax sharing agreement as a wholly-owned subsidiary of ITC Investment Holdings. Additionally, we record income taxes based on our separate company tax position and make or receive tax-related payments with ITC Investment Holdings. In April 2020, ITC Holdings paid $2 million to ITC Investment Holdings for matters related to the State of Michigan income taxes. During the years ended December 31, 2020 and 2019, we received a payment of $2 million from FortisUS for a tax refund that originated prior to establishing the tax sharing agreement.

18. COMMITMENTS AND CONTINGENT LIABILITIES

Environmental Matters

We are subject to federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities relating to investigation and remediation of contamination, as well as other liabilities concerning hazardous materials or contamination, such as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties currently owned or operated by us. Such liabilities may arise even where the contamination does not result from noncompliance with applicable environmental laws. Under some environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share. Although environmental requirements generally have become more stringent and compliance with those requirements more expensive, we are not aware of any specific developments that would increase our costs for such compliance in a manner that would be expected to have a material adverse effect on our results of operations, financial condition or liquidity.

Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Many of the properties that we own or operate have been used for many years and include older facilities and equipment that may be more likely than newer ones to contain or be made from such materials. Some of these properties include aboveground or underground storage tanks and associated piping. Some of them also include large electrical equipment filled with mineral oil, which may contain or previously have contained PCBs. Some of our facilities and electrical equipment may also contain asbestos containment materials. Our facilities and equipment are often situated on or near property owned by others so that, if they are the source of contamination, others’ property may be affected. For example, aboveground and underground transmission lines sometimes traverse properties that we do not own and transmission assets that we own or operate are sometimes commingled at our transmission stations with distribution assets owned or operated by our transmission customers.

Some properties in which we have an ownership interest or at which we operate are, or are suspected of being, affected by environmental contamination. We are not aware of any pending or threatened claims against us with respect to environmental contamination relating to these properties, or of any investigation or remediation of contamination at these properties, that entail costs likely to materially affect us. Some facilities and properties are located near environmentally sensitive areas such as wetlands.

Litigation

We are involved in certain legal proceedings before various courts, governmental agencies and mediation panels concerning matters arising in the ordinary course of business. These proceedings include certain contract disputes, eminent domain and vegetation management activities, regulatory matters and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss.

Rate of Return on Equity Complaints

Two complaints were filed with the FERC by combinations of consumer advocates, consumer groups, municipal parties and other parties challenging the base ROE in MISO. The complaints were filed with the FERC under Section 206 of the FPA requesting that the FERC find the MISO regional base ROE rate (the “base ROE”) for all MISO TO’s, including our MISO Regulated Operating Subsidiaries, to no longer be just and reasonable.

Initial Complaint

On November 12, 2013, the Association of Businesses Advocating Tariff Equity, Coalition of MISO Transmission Customers, Illinois Industrial Energy Consumers, Indiana Industrial Energy Consumers, Inc., Minnesota Large Industrial Group and Wisconsin Industrial Energy Group (collectively, the “complainants”) filed the Initial Complaint with the FERC. The complainants sought a FERC order to reduce the base ROE used in the formula transmission rates for our MISO Regulated Operating Subsidiaries to 9.15%, reducing the equity component of our capital structure and terminating the ROE adders approved for certain Regulated Operating Subsidiaries. The FERC set the base ROE for hearing and settlement procedures, while denying all other aspects of the Initial Complaint. The ROE collected through the MISO Regulated Operating Subsidiaries’ rates during the period November 12, 2013 through September 27, 2016 consisted of a base ROE of 12.38% plus applicable incentive adders.

On September 28, 2016, the FERC issued the September 2016 Order that set the base ROE at 10.32%, with a maximum ROE of 11.35%, effective for the period from November 12, 2013 through February 11, 2015 based on the two-step DCF methodology adopted in previous complaint matters for other utilities. The September 2016 Order required our MISO Regulated Operating subsidiaries to provide refunds, including interest, which were completed in 2017. Additionally, the base ROE established by the September 2016 Order was to be used prospectively from the date of that order until a new approved base ROE was established by the FERC. On October 28, 2016, the MISO TOs, including our MISO Regulated Operating Subsidiaries, filed a request with the FERC for rehearing of the September 2016 Order regarding the short-term growth projections in the two-step DCF analysis. Additional impacts to the base ROE for the period of the Initial Complaint and the related accrued refund liabilities resulted from the November 2019 Order and May 2020 Order issued by the FERC, as discussed below.

Second Complaint

On February 12, 2015, the Second Complaint was filed with the FERC by Arkansas Electric Cooperative Corporation, Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission, Public Service Commission of Yazoo City and Hoosier Energy Rural Electric Cooperative, Inc., seeking a FERC order to reduce the base ROE used in the formula transmission rates of our MISO Regulated Operating Subsidiaries to 8.67%, with an effective date of February 12, 2015.

On June 30, 2016, the presiding ALJ issued an initial decision that recommended a base ROE of 9.70% for the refund period from February 12, 2015 through May 11, 2016, with a maximum ROE of 10.68%, which also would be applicable going forward from the date of a final FERC order. The Second Complaint was dismissed as a result of the November 2019 Order and the dismissal of the complaint was reaffirmed in the May 2020 Order, as discussed below.

Related FERC Orders

In April 2017, the D.C. Circuit Court vacated certain precedent-setting FERC orders that established and applied the two-step DCF methodology for the determination of base ROE for ISO New England TOs. The court remanded the orders to the FERC for further justification of its establishment of the new base ROE for the ISO New England TOs. The vacated orders in the ISO New England matters also provided the precedent for the September 2016 Order on the Initial Complaint and the ALJ initial decision on the Second Complaint for our MISO Regulated Operating Subsidiaries. On October 16, 2018, in the New England matters, the FERC issued an order on remand which proposed a new methodology for 1) determining when an existing ROE is no longer just and reasonable; and 2) setting a new just and reasonable ROE if an existing ROE has been found not to be just and reasonable.

The FERC issued a similar order, the November 2018 Order, in the MISO ROE Complaints, establishing a paper hearing on the application of the proposed new methodology to the proceedings pending before the FERC involving the ROE of the MISO TOs, including our MISO Regulated Operating Subsidiaries. The November 2018 Order included illustrative, non-binding calculations for the ROE that could have been established for the Initial Complaint using the FERC's proposed methodology. The November 2018 Order and our response to the order through briefs and reply briefs did not provide a reasonable basis for a change to the reserve or ROEs utilized for any of the complaint refund periods nor all subsequent periods.

November 2019 Order

On November 21, 2019, the FERC issued an order on the MISO ROE Complaints. The FERC did not adopt the methodology proposed in the November 2018 Order, but rather applied a methodology to the Initial Complaint period that used two financial models to determine the base ROE. The FERC determined that the base ROE for the Initial Complaint should be 9.88% and the top of the range of reasonableness for that period should be 12.24% and that this base ROE should apply during the first refund period of November 12, 2013 to February 11, 2015 and from the date of the September 2016 Order prospectively. In the November 2019 Order, the FERC also dismissed the Second Complaint. Therefore, based on the November 2019 Order, for the Second Complaint refund period from February 12, 2015 to May 11, 2016, no refund is due. As a result, we reversed the aggregate estimated current liability we had previously recorded for the Second Complaint, as noted below in “Financial Statement Impacts”. In addition, for the period from May 12, 2016 to September 27, 2016, no refund is due because no complaint had been filed for that period. The FERC ordered refunds to be made in accordance with the November 2019 Order and, on December 18, 2019, the FERC granted an extension until December 23, 2020 for settlement of the refunds. The MISO TOs, including our MISO Regulated Operating Subsidiaries, and several other parties filed requests for rehearing of the November 2019 Order. The MISO TOs filed their request for rehearing primarily on the basis that the methodology applied by the FERC in the November 2019 Order does not allow the MISO TOs to earn a reasonable rate of return on their investment, as required by precedent. On January 21, 2020, the FERC issued an order granting rehearing for further consideration.

May 2020 Order

On May 21, 2020, the FERC issued an order on rehearing of the November 2019 Order. In this order, the FERC revised its November 2019 Order methodology, finding that three financial models should be used to determine the base ROE, among other revisions. By applying the new methodology, FERC determined that the base ROE for the Initial Complaint should be 10.02% and the top of the range of reasonableness for that period should be 12.62%. The FERC determined that this base ROE should apply during the first refund period of November 12, 2013 to February 11, 2015 and from the date of the September 2016 Order prospectively. The FERC ordered refunds to be made in accordance with the May 2020 Order by December 23, 2020, and on October 8, 2020, the FERC granted an extension to September 23, 2021. In the May 2020 Order, the FERC also reaffirmed its decision to dismiss the Second Complaint and its finding that no refunds would be ordered on the Second Complaint. Our MISO Regulated Operating Subsidiaries are parties to multiple appeals of the September 2016 Order, November 2019 Order and May 2020 Order at the D.C. Circuit Court.

Financial Statement Impacts

As of December 31, 2020, we had recorded an aggregate current regulatory asset and current regulatory liability of $8 million and $13 million, respectively, and as of December 31, 2019, we had recorded an aggregate current regulatory liability of $70 million in the consolidated statements of financial position. These impacts reflect amounts owed from or due to customers under the terms outlined in the May 2020 Order and the November 2019 Order on the Initial Complaint and the periods subsequent to the September 2016 Order. During the year ended December 31, 2020, we refunded $31 million of the regulatory liability to customers. We had recorded an aggregate estimated current regulatory liability in the consolidated statements of financial position of $151 million as of December 31, 2018 for the Second Complaint, which was reversed in November 2019 following the November 2019 Order. Although the November 2019 Order and May 2020 Order dismissed the Second Complaint with no refunds required, it is possible upon appeal that our MISO Regulated Operating Subsidiaries will be required to provide refunds related to the Second Complaint and these refunds could be material.

Our MISO Regulated Operating Subsidiaries currently record revenues at the base ROE of 10.02% established in the May 2020 Order plus applicable incentive adders. See Note 6 for a summary of incentive adders for transmission rates.

The recognition of the obligations associated with the MISO ROE Complaints resulted in the following impacts to the consolidated statements of comprehensive income:

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
Revenue increase	$ 32	$ 69	$ 1
Interest expense (decrease) increase	(3)	(12)	7
Estimated net income increase (reduction)	25	61	(4)

As of December 31, 2020, our MISO Regulated Operating Subsidiaries had a total of approximately $5 billion of equity in their collective capital structures for ratemaking purposes. Based on this level of aggregate equity, we estimate that each 10 basis point change in the authorized ROE would impact annual consolidated net income by approximately $5 million.

Purchase Obligations

At December 31, 2020, we had purchase obligations of $83 million representing commitments for materials, services and equipment that had not been received as of December 31, 2020, primarily for construction and maintenance projects for which we have an executed contract. Of these purchase obligations, $73 million is expected to be paid in 2021, with the majority of the items related to materials and equipment that have long production lead times.

Other Commitments

METC

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

Amended and Restated Easement Agreement. Under the Easement Agreement, Consumers Energy provides METC with an easement to the land on which a majority of METC's transmission towers, poles, lines and other transmission facilities used to transmit electricity for Consumers Energy and others are located. The term of the Easement Agreement runs through December 31, 2050 and is subject to 10 automatic 50-year renewals thereafter unless METC gives notice of nonrenewal at least one year in advance. METC pays Consumers Energy $10 million in annual rent per year for the easement and also pays for any rentals, property, taxes, and other fees related to the property covered by the Easement Agreement. Payments to Consumers Energy under the Easement Agreement are charged to operation and maintenance expenses.

ITC Midwest

Operations Services Agreement For 34.5 kV Transmission Facilities. ITC Midwest and IP&L entered into the OSA under which IP&L performs certain operations functions for ITC Midwest's 34.5 kV transmission system. The OSA provides that when ITC Midwest upgrades 34.5 kV facilities to higher operating voltages it may notify IP&L of the change and the OSA is no longer applicable to those facilities.

ITC Great Plains

Amended and Restated Maintenance Agreement. Mid-Kansas and ITC Great Plains have entered into the Mid-Kansas Agreement pursuant to which Mid-Kansas has agreed to perform various field operations and maintenance services related to certain ITC Great Plains assets.

Concentration of Credit Risk

Our credit risk is primarily with DTE Electric, Consumers Energy and IP&L, which were responsible for approximately 21.6%, 23.9% and 23.9%, respectively, or $265 million, $292 million and $292 million, respectively, of our consolidated billed revenues for the year ended December 31, 2020. These percentages and amounts of total billed revenues of DTE Electric, Consumers Energy and IP&L include the collection of 2018 revenue accruals and deferrals and exclude any amounts for the 2020 revenue accruals and deferrals that were included in our 2020 operating revenues but will not be billed to our customers until 2022. Under DTE Electric's and Consumers Energy's current rate structure, DTE Electric and Consumers Energy include in their retail rates the actual cost of transmission services provided by ITCTransmission and METC, respectively, in their billings to their customers, effectively passing through to end-use consumers the total cost of transmission service. IP&L currently includes in their retail rates an allowance for transmission services provided by ITC Midwest in their billings to their customers. However, any financial difficulties experienced by DTE Electric, Consumers Energy or IP&L may affect their ability to make payments for transmission service to ITCTransmission, METC, and ITC Midwest, which could negatively impact our business. MISO, as our MISO Regulated Operating Subsidiaries' billing agent, bills DTE Electric, Consumers Energy, IP&L and other customers on a monthly basis and collects fees for the use of the MISO Regulated Operating Subsidiaries' transmission systems. SPP is the billing agent for ITC Great Plains and bills transmission customers for the use of ITC Great Plains transmission systems. MISO and SPP have implemented strict credit policies for its members' customers, which include customers using our transmission systems. Specifically, MISO and SPP require a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit scoring model and other factors, from any customer using a member's transmission system.

The financial results of ITC Interconnection are currently not material to our consolidated financial statements, including billed revenues.

19. SUPPLEMENTAL FINANCIAL INFORMATION

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported on the consolidated statements of financial position that sum to the total of the same such amounts shown in the consolidated statements of cash flows:

	December 31,			
(In millions of USD)	2020	2019	2018	2017
Cash and cash equivalents	$ 4	$ 4	$ 6	$ 66
Restricted cash included in:				
Other non-current assets	2	2	4	2
Total cash, cash equivalents and restricted cash	$ 6	$ 6	$ 10	$ 68

Restricted cash included in other non-current assets primarily represents cash on deposit to pay for vegetation management, land easements and land purchases for the purpose of transmission line construction.

Supplementary Cash Flow Information

	Year Ended December 31,		
(In millions of USD)	2020	2019	2018
Supplementary cash flows information:			
Interest paid (net of interest capitalized)	$ 236	$ 228	$ 223
Income taxes paid	2	—	—
Income tax refunds received	2	3	13
Supplementary non-cash investing and financing activities:			
Additions to property, plant and equipment and other long-lived assets (a)	135	92	94
Allowance for equity funds used during construction	27	29	33
Right-of-use assets obtained in exchange for new operating lease liabilities	—	5	—

(a) Amounts consist of current and accrued liabilities for construction, labor, materials and other costs that have not been included in investing activities. These amounts have not been paid for as of December 31, 2020, 2019 or 2018, respectively, but will be or have been included as a cash outflow from investing activities for expenditures for property, plant and equipment when paid.

Excess tax benefits are recognized as an adjustment to income tax expense in the consolidated statements of comprehensive income. Cash retained as a result of those excess tax benefits is presented in the consolidated statements of cash flows as cash inflows from operating activities.

20. SEGMENT INFORMATION

We identify reportable segments based on the criteria set forth by the FASB regarding disclosures about segments of an enterprise, including the regulatory environment of our subsidiaries and the business activities performed to earn revenues and incur expenses.

Regulated Operating Subsidiaries

We aggregate ITCTransmission, METC, ITC Midwest, ITC Great Plains and ITC Interconnection into one reportable operating segment based on their similar regulatory environment and economic characteristics, among other factors. They are engaged in the transmission of electricity within the United States, earn revenues from the same types of customers and are regulated by the FERC.

ITC Holdings and Other

Information below for ITC Holdings and Other consists primarily of a holding company whose activities include debt financings and general corporate activities. The other subsidiaries of ITC Holdings, excluding the Regulated Operating Subsidiaries, do not have significant operations.

2020 (In millions of USD)	Regulated Operating Subsidiaries	ITC Holdings and Other	Reconciliations/ Eliminations	Total
Operating revenues	$ 1,333	$ 1	$ (36)	$ 1,298
Depreciation and amortization	218	1	—	219
Interest expense, net	118	122	—	240
Income (loss) before income taxes	683	(140)	—	543
Income tax provision (benefit)	179	(43)	—	136
Net income	504	407	(504)	407
Property, plant and equipment, net	9,319	8	—	9,327
Goodwill	950	—	—	950
Total assets (a)	10,710	5,830	(5,715)	10,825
Capital expenditures	886	—	(1)	885

2019 (In millions of USD)	Regulated Operating Subsidiaries	ITC Holdings and Other	Reconciliations/ Eliminations	Total
Operating revenues	$ 1,358	$ —	$ (31)	$ 1,327
Depreciation and amortization	201	2	—	203
Interest expense, net	105	119	—	224
Income (loss) before income taxes	710	(150)	—	560
Income tax provision (benefit)	179	(47)	—	132
Net income	531	428	(531)	428
Property, plant and equipment, net	8,573	9	—	8,582
Goodwill	950	—	—	950
Total assets (a)	9,946	5,402	(5,290)	10,058
Capital expenditures	874	—	(9)	865

2018	Regulated Operating Subsidiaries	ITC Holdings and Other	Reconciliations/ Eliminations	Total
(In millions of USD)				
Operating revenues	$ 1,185	$ —	$ (29)	$ 1,156
Depreciation and amortization	179	1	—	180
Interest expense, net	110	114	—	224
Income (loss) before income taxes	585	(144)	—	441
Income tax provision (benefit)	148	(37)	—	111
Net income	437	330	(437)	330
Property, plant and equipment, net	7,901	9	—	7,910
Goodwill	950	—	—	950
Total assets (a)	9,224	4,977	(4,872)	9,329
Capital expenditures	773	—	(4)	769

(a) Reconciliation of total assets results primarily from differences in the netting of deferred tax assets and liabilities in our segments as compared to the classification in our consolidated statements of financial position.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.*

None.

ITEM 9A. *CONTROLS AND PROCEDURES.*

Management's Report on Internal Control Over Financial Reporting is included in Item 8 of this Form 10-K.

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that material information required to be disclosed in our reports that we file or submit under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required financial disclosure. In designing and evaluating the disclosure controls and procedures, management recognized that a control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with a company have been detected.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective, at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *OTHER INFORMATION.*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.*

DIRECTORS

Our Bylaws provide for the election of directors at each annual meeting of shareholders. Each director serves until the next annual meeting and until his or her successor is elected and qualified, or until his or her resignation or removal.

Pursuant to the Merger Agreement and the Shareholders Agreement, the Board must consist of the Chief Executive Officer of the Company (Ms. Apsey), a representative of Eiffel, the GIC subsidiary that is a minority investor in ITC Investment Holdings (Mr. Greenbaum), a minority of representatives of Fortis (Messrs. Hutchens and Laurito) and a majority of directors who are independent of Fortis. All directors must be independent of any "market participant" in MISO and SPP and a majority of the directors must be "independent" as defined in the Shareholders Agreement. See "Item 13 Certain Relationships And Related Transactions, And Director Independence — Director Independence."

Linda H. Apsey, 51. Ms. Apsey became President and Chief Executive Officer of the Company in November 2016 and was elected a director of the Company in January 2017. From May 2016 through January 2017, Ms. Apsey served as the Company's Executive Vice President and Chief Business Unit Officer, where she was responsible for leading all aspects of the financial and operational performance of our five Regulated Operating Subsidiaries and the Company's development. She had previously served as the Company's Executive Vice President, Chief Business Unit Officer and President, ITC Michigan since February 2015 where she was responsible for leading all aspects of the financial and operational performance of the Company's five

Regulated Operating Subsidiaries and acting as the business unit head and president of the ITCTransmission and METC operating companies. Ms. Apsey currently serves as a director of the Fortis utility subsidiary, FortisAlberta Inc.

Robert A. Elliott, 65. Mr. Elliott became a director of the Company in January 2017. Mr. Elliott has served as President and Owner of Elliott Accounting, an accounting, income tax and management advisory services organization in Tucson, Arizona, since 1983. He also serves as an Investment Advisor Representative for Greenberg Financial Group, a brokerage firm, a position in which he has served since 2001. Mr. Elliott is currently the Chairman of the Board of UNS Energy Corporation, a subsidiary of Fortis, and has been a board member of that company since 2014. Mr. Elliott currently serves on the board of directors of AAA Auto Club Partners and AAA Mountain West Group and served as the Chair of the board of directors of AAA Mountain West Group from 2016 to 2020. He previously served on the board of directors of AAA Arizona Inc. from 2007 to 2016 and AAA CSAA Insurance from 2018 to 2020. The Board selected Mr. Elliott to serve as a director because of his accounting experience, his familiarity with Fortis subsidiary operations and his experience serving as a leader on other boards of directors.

Albert Ernst, 71. Mr. Ernst became a director of the Company in January 2017. Mr. Ernst was also a member of the ITC Holdings Board of Directors from August 2014 through the closing of the transactions resulting from the Merger Agreement in October 2016, as described in the Merger Agreement. Mr. Ernst is a retired member of the law firm of Dykema Gossett PLLC, where he also served as director of Dykema's Energy Industry Group. His experience with companies in the public utility, energy, transmission, telecommunications and rural electric cooperative fields spans more than three decades. With Dykema, Mr. Ernst worked with leading energy clients including our subsidiaries, ITCTransmission and METC. He also served as a consultant on utility-related matters to the U.S. Department of Defense, the Department of Energy and the General Services Administration. The Board selected Mr. Ernst to serve as a director due to his lifelong career in the energy industry, as well as his invaluable experience with public utility and energy matters and decades of experience in the practice of law.

Debora M. Frodl, 55. Ms. Frodl became a director of the Company in August 2020. Ms. Frodl is the founder of DF Strategies, a strategic consultancy firm in Minneapolis, MN, since 2018. She previously enjoyed a 28-year career at General Electric, where she most recently was Global Executive Director, Ecomagination from December 2012 to December 2017. Ms. Frodl gained over twenty years of senior executive experience at GE Capital, serving in roles including Senior Vice President and CEO and President. Ms. Frodl currently serves as a member of the Board of Directors for Renewable Energy Group, Inc., XL Fleet Corporation, and Spring Valley Acquisition Corporation. Since 2014, Ms. Frodl has served as an ambassador for the US Department of Energy's Clean Energy, Education & Empowerment for Women Initiative. She also serves on the Advisory Board for the National Renewable Energy Lab, Joint Institute of Strategic Energy Analysis and University of Minnesota, Institute on the Environment. The Board selected Ms. Frodl to serve as a director due to her career in the energy industry, and her leadership experience and familiarity within the geographic region in which the Company operates and conducts its business.

Alexander I. Greenbaum, 37. Mr. Greenbaum became a director of the Company in July 2019. Mr. Greenbaum is the North America Head of Infrastructure for GIC. In this role he is responsible for acquisitions and asset management for a diverse portfolio of infrastructure assets. Prior to joining GIC in May 2015, he was an Executive Director in the Infrastructure group of UBS Investment Bank from July 2005 until May 2015. Mr. Greenbaum currently serves on the board of directors of Tallgrass Energy, LP, a partnership that owns, operates, acquires and develops midstream energy assets in North America, and Genesee & Wyoming Inc., a railroad holding company that operates railroads in North America and Europe. He previously served on the boards of directors of Arrowhead ST Holdings, a crude oil pipeline operator, HEP Catalyst InvestCo, a crude oil and natural gas gathering and processing company that operates in the Permian Basin, Starwest Generation, an independent power producer with operations in Arizona, and Texas Transmission Holdings Company. Mr. Greenbaum was appointed as a member of our Board of Directors by Eiffel.

Lt. Gen. Ronnie Hawkins, Jr., USAF, Retired, 65. Lt. Gen. Hawkins, Jr. became a director of the Company in June 2020. Lt. Gen. Hawkins Jr. was appointed as President of Angelo State University, which is part of the Texas Tech University System, in 2020. Lt. Gen. Hawkins Jr. is also the President and CEO of the Hawkins Group, a consultancy focusing on digital, information technology and cybersecurity challenges for Fortune 500 clients and the U.S. Government. He founded the Hawkins Group in 2015 after serving more than a 37-year decorated career in the United States Air Force, which included leadership roles in critical infrastructure and key information systems used by the Department of Defense and its coalition partners. The Board selected Lt. Gen. Hawkins Jr. due to his vast knowledge of cybersecurity and information systems as well as his leadership experience.

David G. Hutchens, 54. Mr. Hutchens became a director of the Company in January 2021. Mr. Hutchens is the President and Chief Executive Officer of Fortis and has served as such since January 2021. Prior to his current position, Mr. Hutchens was appointed to Chief Operating Officer of Fortis in January 2020 while concurrently serving as the Chief Executive Officer of UNS Energy Corporation, a position in which he held since May 2014. Mr. Hutchens also served as Executive Vice President, Western Utility Operations with Fortis from 2018 to 2020. His career in the energy sector spans more than 25 years, having held a variety of positions at electric and gas utilities in Arizona. He currently serves as a director of the Fortis utility subsidiaries, FortisBC, Fortis Alberta and UNS Energy Corporation.

James P. Laurito, 64. Mr. Laurito became a director of the Company in October 2016. Mr. Laurito has served as Fortis' Executive Vice President, Business Development since April 2016 and was named Chief Technology Officer in 2018. Previously, Mr. Laurito served as the President and Chief Executive Officer of Fortis' Central Hudson Gas & Electric Corporation subsidiary from January 2010 to November 2014. Prior to joining Central Hudson, Mr. Laurito served as the President and Chief Executive Officer of both New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation, subsidiaries of Avangrid, Inc. Mr. Laurito has been Chairman of the Hudson Valley Economic Development Corporation since January 1, 2015 and currently serves on the board of Belize Electricity Co. Ltd. and Fortis' Central Hudson Gas & Electric Corporation subsidiary.

Sandra E. Pierce, 62. Ms. Pierce was appointed as Chair of the Board of Directors of the Company in May 2020 and has served as a director of the Company since January 2017. Ms. Pierce is Senior Executive Vice President, Private Client Group & Regional Banking Director and Chair of Michigan for Huntington National Bank. Ms. Pierce joined Huntington in 2016 after its merger with FirstMerit Corporation in 2016. While at FirstMerit, Ms. Pierce served as Vice Chairman of FirstMerit Corporation and Chairman and CEO of FirstMerit Michigan, from 2013 to 2016. Ms. Pierce currently serves as a board member of Barton Malow Enterprises, Penske Automotive Group and American Axle & Manufacturing, Inc. She also serves as the vice chair of Business Leaders of Michigan, chair of the Detroit Financial Advisory Board and the chair of the Henry Ford Health System. The Board selected Ms. Pierce to serve as a director due to her leadership experience and familiarity with the geographic region in which the Company operates and conducts business.

Kevin L. Prust, 65. Mr. Prust became a director of the Company in January 2017. Mr. Prust retired in 2014 as Executive Vice President and Chief Financial Officer of The Weitz Company, LLC, a large national and international construction firm, a position he held since joining the company in 2009. Prior to that, Mr. Prust was with McGladrey & Pullen LLP, a national CPA firm, from 1978 through 2008 serving in various positions and becoming partner in 1985. Mr. Prust previously served on the board of Mercy Medical Center, in Des Moines, Iowa from 2009 to 2018. In 2015 Mr. Prust served on the board of Stock Building Supply Holdings, Inc. until the company was acquired. The Board selected Mr. Prust to serve as a director because of the expansive financial and accounting experience he obtained as a chief financial officer as well as his familiarity with the geographic region in which the Company operates and conducts business. The Board has determined that Mr. Prust is an "audit committee financial expert", as that term is defined under SEC rules.

A. Douglas Rothwell, 64. Mr. Rothwell became a director of the Company in October 2017. Mr. Rothwell served as President and CEO of Business Leaders for Michigan - a business roundtable of the state's top 100 CEOs from 2005 through 2020. Mr. Rothwell currently chairs the University of North Carolina at Chapel Hill's ("UNC") Ackland Museum board in addition to serving as an Executive Residence for Economic Development at UNC. He previously chaired the Michigan Economic Development Corporation, the American Center for Mobility and the UNC Board of Visitors. The Board selected Mr. Rothwell to serve as a director because of his vast experience working with business leaders in various industries to foster business development and growth and his familiarity and business contacts within the geographic region in which the Company operates and conducts business.

EXECUTIVE OFFICERS

Set forth below are the names, ages and titles of our current executive officers and a description of their business experience. Our executive officers serve as executive officers at the pleasure of the Board of Directors.

Linda H. Apsey, 51. Ms. Apsey's background is described above under "Directors."

Gretchen L. Holloway, 46. Ms. Holloway was named Senior Vice President and Chief Financial Officer in July 2017. Prior to this role, Ms. Holloway served as Vice President, Interim Chief Financial Officer and Treasurer, a position in which she served since October 2016. In her role, Ms. Holloway is responsible for the Company's accounting, internal audit, treasury, financial planning and analysis, management reporting, risk management and tax functions. From May 2016 to October 2016, Ms. Holloway was Vice President and Treasurer and from November 2015 until May 2016, Ms. Holloway served as Vice President, Finance and Treasurer of the Company. In this role and her immediate past role, she was responsible for all treasury and corporate planning activities including cash management and as the Company's liaison with the investment banking community and rating agencies. Ms. Holloway served from February 2015 to November 2015 as Vice President, Finance of the Company, where she was responsible for corporate finance activities including oversight of the budget and forecast processes and other financial analysis. Ms. Holloway currently serves as a member of the Finance & Audit Committee for the Children's Hospital of Michigan Foundation and as a member of the Board of Directors of Inforum.

Jon E. Jipping, 54. Jon E. Jipping has served as Executive Vice President and Chief Operating Officer since June 2007. Mr. Jipping is responsible for transmission system planning, system operations, engineering, supply chain, field construction and maintenance, and information technology. Prior to this appointment, Mr. Jipping served as Senior Vice President - Engineering and was responsible for transmission system design, project engineering and asset management. Mr. Jipping joined the Company as Director of Engineering in March 2003, was appointed Vice President - Engineering in 2005 and was named Senior Vice President in February 2006. Mr. Jipping currently serves on the board of Wataynikaneyap Power PM Inc., an entity owned by FortisOntario, Inc., a subsidiary of Fortis, which was created to develop and operate transmission to connect remote First Nation communities to the electrical grid in northwestern Ontario, Canada. He was appointed to the Michigan Technological University Board of Trustees as a Board Member in 2020.

Christine Mason Soneral, 48. Christine Mason Soneral has served as Senior Vice President, General Counsel, Secretary and Chief Compliance Officer since October 2020. She was named Senior Vice President and General Counsel in April 2015 and served as Vice President and General Counsel from February 2015 through this appointment. She is responsible for all corporate legal affairs and the leadership of our legal department, which includes the legal, real estate, contract administration and corporate compliance functions. Prior to this role, Ms. Mason Soneral was Vice President and General Counsel-Utility Operations since 2007 and was responsible for legal matters connected with the operations, capital projects, contract, regulatory, property and litigation matters of the Company's Regulated Operating Subsidiaries. Ms. Mason Soneral served on the board of Citizens Research Council, a privately funded, not-for-profit public affairs research organization from 2014 to 2020. Ms. Mason Soneral also currently serves as a member of the Michigan State University College of Social Science's External Advisory Board and is a Co-Founder and Director of Michigan State University's Women's Leadership Institute.

Krista K. Tanner, 46. Ms. Tanner has served as our Senior Vice President and Chief Business Unit Officer since February 2019. Ms. Tanner is responsible for strategic direction, customer service, local government and community affairs and financial performance for four of the Company's operating subsidiaries: ITC Midwest, ITC Great Plains, ITCTransmission and METC. Ms. Tanner joined the Company in November 2014 where she served as Vice President, ITC Holdings and President, ITC Midwest. In this role she served as the business unit head, providing leadership and strategic direction for ITC Midwest. Ms. Tanner joined the Company from Alliant Energy, where she served as director of regulatory policy from 2011 to 2014. While at Alliant Energy she directed Alliant Energy's regional and federal regulatory policy group and led Alliant Energy's legal strategy across regulatory jurisdictions. Ms. Tanner previously served as a member of the Board of Directors of the Midwest Reliability Organization from 2017 to 2019. Ms. Tanner currently serves as a member of the Board of Directors of Delta Dental of Iowa.

Code of Conduct and Ethics

We have adopted a Code of Conduct and Ethics that applies to all of our directors, employees and executive officers, including our chief executive officer, chief financial officer and principal accounting officer. The Code of Conduct and Ethics, as currently in effect (together with any amendments that may be adopted from time to time), is available on our website at www.itc-holdings.com. To the extent required by the Code of Conduct and Ethics or by applicable law, we will post any amendments to the Code of Conduct and Ethics and any waivers

Table of Contents

that are required to be disclosed by the rules of the SEC on our website, within the required periods.

ITEM 11. *EXECUTIVE COMPENSATION.*

COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis describes the elements of compensation for our Chief Executive Officer (or "CEO"), our Chief Financial Officer and the three other most highly compensated executive officers who were serving as such at December 31, 2020, and our former Executive Vice President and Chief Administrative Officer. We refer to these individuals collectively as the "named executive officers" or "NEOs".

The Company's named executive officers for 2020 were:

Name	Position
Linda H. Apsey	President and Chief Executive Officer
Gretchen L. Holloway	Senior Vice President and Chief Financial Officer
Jon E. Jipping	Executive Vice President and Chief Operating Officer
Christine Mason Soneral	Senior Vice President, General Counsel, Secretary and Chief Compliance Officer
Krista Tanner	Senior Vice Present and Chief Business Unit Officer
Daniel J. Oginsky	Former Executive Vice President and Chief Administrative Officer

Mr. Oginsky, whose employment with the Company terminated in May 2020, is included as an NEO in the discussion below in accordance with applicable SEC rules.

Executive Summary

The Governance and Human Resources Committee (the "Committee") is responsible for determining the compensation of our NEOs and administering the plans in which the NEOs participate. The goals of our compensation system are to attract first-class executive talent in a competitive environment and to motivate and retain key employees who are crucial to our success by rewarding Company and individual performance that promotes long-term sustainable growth and increases shareholder value. The key components of our NEOs' compensation package include base salary, annual cash incentive bonuses, long-term equity incentives, as well as certain perquisites and other benefits. In determining the amount of NEO compensation, we consider competitive compensation practices of other utilities and similarly sized organizations, the executive's individual performance against objectives, the executive's responsibilities and expertise, and our performance in relation to annual goals that are designed to strengthen and enhance our value.

The Committee made the following decisions with regard to executive compensation in 2020:

- **Base salary increases**. Base salary increases were provided to each of our NEOs in 2020 to reward individual performance and to remain competitive and aligned with market.
- **Annual cash incentive bonuses.** The NEOs earned cash incentive bonuses for 2020 performance of approximately 141% of target. This was based on achieving 85% of the performance targets established under the annual corporate performance bonus plan in early 2020 and achievement of certain performance factors which resulted in a bonus multiplier of 1.66. See "Compensation Discussion and Analysis - Key Components of Our NEO Compensation Program - Annual Corporate Performance Bonus."
- **Long-term equity incentives**. We granted long-term equity incentive awards to our NEOs in January 2020. Total award opportunities were set as a percentage of base salary and delivered one-third in the form of SBUs and two-thirds in the form of PBUs.

Overview and Philosophy

The objectives of our compensation program are to attract first-class executive talent in a competitive environment and to motivate and retain key employees who are crucial to our success by rewarding Company and individual performance that promotes long-term sustainable growth and increases shareholder value by:

- Performing best-in-class utility operations;
- Improving reliability, reducing congestion, and facilitating access to generation resources; and
- Utilizing our experience and skills to seek and identify opportunities to invest in needed transmission and to optimize the value of those investments.

Our compensation program is designed to motivate and reward individual and corporate performance. Our compensation philosophy is to:

- Provide for flexibility in pay practices to recognize our unique position and growth proposition;
- Use a market-based pay program aligned with pay-for-performance objectives;
- Leverage incentives, where possible, and align long-term incentive awards with improvements in our financial performance and shareholder value;
- Provide benefits through flexible, cost-effective plans while taking into account business needs and affordability; and
- Provide other non-monetary awards to recognize and incentivize performance.

Risk and Reward Balance

When reviewing the compensation program, the Committee considers the impact of the program on the Company's risk profile. The Committee believes that the compensation program has been structured with the appropriate mix and design of elements to provide strong incentives for executives to balance risk and reward, without excessive risk taking.

The Committee engaged FW Cook, its independent compensation consultant, to conduct an annual comprehensive compensation program risk assessment. In July 2020, FW Cook reviewed the attributes and structure of our executive compensation programs for the purpose of identifying potential sources of risk within the program design. The review covered compensation plan design and administration/governance risk.

Based on a report from FW Cook concluding that the Company's compensation programs do not create risks that are reasonably likely to have a material adverse impact on the Company, the Committee concluded that none of our compensation programs and features contain elements that create material risk to the Company. Risk mitigating factors with respect to the Company's compensation programs included a market competitive pay mix, the linking of pay to performance through annual cash bonus and long-term equity incentive plans, caps on annual cash bonus and long-term equity incentive plan payouts, various performance measures that are both financially and operationally focused, stock ownership guidelines, prohibition on hedging and pledging, oversight by an independent committee of directors, regular review of NEO tally sheets and engagement of an independent compensation consultant.

Benchmarking and Relationship of Compensation Elements

Benchmarking. We reviewed market competitive target pay levels from two distinct market samples, utility and general industry data, as reflected in published surveys. FW Cook, the Committee's independent advisor, compiled data for the following components of compensation — base salary, target annual cash bonus incentive and target long-term incentive, as well as target total cash compensation and target total direct compensation. Position-specific market target pay levels are reviewed for utility-specific data from the Willis Towers Watson Energy Services Executive Compensation Survey and general industry data from the Willis Towers Watson General Industry Executive Compensation Survey. The energy services data is used as our primary source with the general industry data provided as an additional reference point for positions other than those specific to the utility industry. The market data were aged and size-adjusted to correspond to our adjusted revenue scope. The adjusted revenue scope accounts for our unique business model and reflects the competitive incremental revenue that would normally be embedded in rates to reflect a typical cost of goods sold factor.

Our compensation strategy is to target compensation at the median (50th percentile) of the energy services benchmark data, plus or minus 20%, based on consideration of individual characteristics (performance, experience, etc.), internal equity and other factors. The Committee adopted this strategy in October 2019. In November 2019, the Committee reviewed the benchmarking study conducted by its independent consultant comparing NEO target total direct compensation, which is the sum of base salary, target annual incentives and target long-term incentives, to the 25th, 50th and 75th percentile survey data to assess the market competitiveness of our compensation opportunities. Overall, the study found target total direct compensation provided to our NEOs is at the high end of the targeted competitive position.

Use of Tally Sheets. The Committee reviews tally sheets, every other year, as prepared by management to facilitate its assessment of the total annual compensation of our NEOs. The tally sheets contain annual cash compensation (salary and bonuses), long-term equity incentives, benefit contributions and perquisites. In addition, the tally sheets include retirement program balances, outstanding vested and unvested equity values and potential severance and termination scenario values.

Pay Review Process. In addition to the Committee's benchmarking analysis, our CEO reviewed and examined market survey compensation levels and practices, as well as individual responsibilities and performance, our compensation philosophy and other related information to develop proposed compensation for each of our NEOs, other than herself. Ms. Apsey evaluated the performance of the NEOs, other than herself, and made recommendations on their salaries, target cash bonus incentive levels and long-term equity incentive awards. The Committee considered these recommendations in its decision making and conferred with FW Cook, its compensation consultant, to understand the impact and result of any such recommendations. The Committee uses market data and recommendations from FW Cook and makes recommendations on Ms. Apsey's salary, cash bonus incentive targets and long-term equity incentive awards to the Board of Directors. The Board of Directors (other than Ms. Apsey) evaluates Ms. Apsey's performance and considers the Committee's recommendations in its decision making.

The Committee reviewed and considered each element of compensation and the resulting target total direct compensation, along with the objectives of our compensation program, the input of the CEO and the market data to set the 2020 target pay levels. The Committee did not determine the mix of compensation elements using a pre-set formula. In setting executive compensation levels, the Committee retained full discretion to consider or disregard data collected through benchmarking studies. Compensation decisions also considered individual and Company performance, retention concerns, the importance of the position, internal equity and other factors.

Key Components of Our NEO Compensation Program

The key components of our executive compensation program are discussed below.

- Base Salary — provides sufficient competitive pay to attract and retain experienced and successful executives.
- Cash Bonus Incentive — encourages and rewards contributions to our annual corporate performance goals.
- Long Term Equity Incentives — encourages a multi-year focus on performance, rewards building long-term shareholder value and helps retain NEOs.

The other elements of our executive compensation program are discussed below under the heading "Other Components of Our Executive Compensation Program" which summarize the benefit programs that are available to our NEOs.

In aggregate, the NEOs' target total direct compensation value (salary, annual target bonus and long-term incentive opportunities) was at the high end of the targeted competitive position of median plus or minus 20% when compared to the energy services benchmark data. Current positioning reflects median base salaries and above median target bonus and long-term incentive opportunities. The Committee continues to monitor and balance competitive practice, talent needs and cost considerations when setting compensation.

Base Salary

The Committee annually reviews and approves the base salaries, and any adjustments thereto, of the NEOs. In making these determinations, the Committee considers the executive's job responsibilities, individual performance, leadership and years of experience, the performance of the Company, the recommendation of the CEO (except for the base salary of the CEO) and the target total direct compensation package as well as the benchmarking analysis conducted by its advisor.

The 2020 base salaries for the NEOs, including any year-over-year change, were:

NEO	2019 Base Salary	2020 Base Salary	Percent Increase
Linda H. Apsey	$ 800,000	$ 816,000	2.0 %
Gretchen L. Holloway	390,000	397,800	2.0 %
Jon E. Jipping	580,000	585,800	1.0 %
Christine Mason Soneral	390,000	393,900	1.0 %
Krista Tanner	325,000	339,600	4.5 %
Daniel J. Oginsky	485,000	485,000	— %

Ms. Tanner's higher percentage increase reflects her expanding role and responsibilities.

Annual Corporate Performance Bonus

Early each year, the Committee approves our annual corporate performance bonus plan goals and targets, which are based on key Company objectives relating to operational excellence and superior financial performance. The corporate performance goals and targets were designed to align the interests of customers, the shareholder and management, and encourage teamwork and coordination among all of our executives and employees with a common focus on the growth and success of the Company. Target levels for the corporate performance goals were determined based on long-term strategic plans, historical performance, expectations for future growth and desired improvement over time.

The annual corporate performance bonus plan goals were individually weighted. Weights were assigned to each goal based on areas of focus during the year and difficulty in achieving target performance. Weights were also assigned so that there was a balance between operational and financial goals. Each goal operated independently, and, for most goals, there was not a range of acceptable performance; if a goal was not achieved, there was no payout for that goal. Where performance goals were stated in a range, the threshold goals were generally expected to be achieved while the maximum goals were considered "stretch" goals with lower expectation of achievement. The bonus goal targets were established to motivate NEOs toward operational excellence and superior financial performance and were designed to be challenging to meet, while remaining achievable.

For 2020, Financial goals, representing 20%, plus Safety & Compliance, representing 20%, determined 40% of the target bonus opportunity, while System Performance, representing 30%, and Capital Project Plan, representing 30%, determined the remaining 60% of the target bonus opportunity. This reflected the inherent importance of driving operational performance, reliability and needed investment in our transmission system for the benefit of our customers.

The annual corporate performance bonus plan consisted of three primary measurement categories: Financial, Safety & Compliance, and System Performance. Our safety, operations and security goals were established to deliver high performance in core company operations. Benchmarks and metrics were used in connection with these goals to establish a level of performance in the top decile or quartile within our industry. Likewise, our infrastructure protection goals led to the deployment of industry leading practices resulting in a generally enhanced security posture.

Corporate performance goal criteria approved by the Committee for 2020, the rationale for the target goal (in some cases in relation to the prior year target) and actual bonus results, were as set forth below.

Financial goals represented 20% of the total maximum annual bonus target and included specific measures for Non-Field Operation and Maintenance Expense and Net Income.

Category	Goal	Rationale for Goal	Rationale for Target Goal	Potential Payout	2020 Results	Actual Payout
Financial 20% Maximum Potential Payout	Non-field Operation and Maintenance Expense and General and Administrative Expenses	Controlling general and administrative expenses is an important part of controlling rates charged to transmission customers.	Target is consistent with the approach used in 2019 and based on the 2020 Board-approved budget. Non-Field O&M and G&A expense at or under budget of $168M.	10 %	$140M	10%
	Adjusted Net Income (1)	Represents the Company's financial performance as it reflects a true measure of earnings contributions from our Regulated Operating Subsidiaries.	Target based on the 2020 Board-approved budget. Adjusted Net Income at or above $491M to achieve 10%; Adjusted Net Income at or above $467M to achieve 5%.	5% - 10%	$496M	10%
Total				**20 %**		**20%**

Safety & Compliance goals represented 20% of the total maximum annual bonus target and included specific measures for Lost Time, Recordable Incidents and Infrastructure Protection.

Category	Goal	Rationale for Goal	Rationale for Target	Potential Payout	2020 Results	Actual Payout
Safety & Compliance 20% Maximum Potential Payout	Safety as measured by lost time	Maintaining the safety of our employees and contractors is a core value and is at the foundation of our success.	Target number of incidents remained the same as prior years and was based on industry top decile performance, which reflects an aggressive view and philosophy on the importance of safety. 2 or fewer lost work day cases for injuries to Company employees and specified contract employees.	5 %	0	5%
	Safety as measured by recordable incidents	Maintaining the safety of our employees and contractors is a core value and is at the foundation of our success.	Target number of incidents reduced by 1 from prior year and was based on industry top decile performance, which reflects an aggressive view and philosophy on the importance of safety. 8 or fewer recordable incidents for injuries to Company employees and specified contract employees.	5 %	2	5%
	Infrastructure Protection	Maintaining cyber and physical security is critical to ensuring system reliability and ongoing operations.	Goal focused on implementing updated security objectives. Emphasized securing our information systems and physical space, helping protect our most important assets. Implementation of the 2020 Cyber Plan and Physical Security Plan, as presented to and approved by the Board of Directors, implementation of each Plan worth 5%.	10 %	Completed	10%
Total				**20 %**		**20 %**

System Performance goals represented 60% of the total maximum annual bonus target and included specific measures for System Outages, Maintenance Plans and Capital Project Plan. Achievement of targets for outage frequency were made more difficult for ITC Midwest in 2020 from previous years due to improved system performance.

Table of Contents

Category	Goal	Rationale for Goal	Rationale for Target	Potential Payout	2020 Results	Actual Payout
	Outage frequency	Reducing and limiting system outages are critical to ensuring system reliability.	Target unchanged from prior year for ITCTransmission and METC, reduced from prior year for ITC Midwest; all targets aligned with industry benchmark data. Number of Forced, Sustained Line Outages, excluding the "External" cause classification, for: ITCTransmission (13 or fewer, representing top decile performance); METC (25 or fewer, representing top decile performance); ITC Midwest (63 or fewer, representing a reduction of 3 outages and top decile performance, no more than 52 at the 69kV level representing top quartile performance.); Each target is worth 5%.	15 %	ITCTransmission - 13 METC - 32 ITC Midwest - 63/50	10%
System Performance and Capital Project Plan 60% Maximum Potential Payout	Field Operation and Maintenance Plan	Performing necessary preventive maintenance is critical to ensuring system reliability.	Target is reflective of goal to complete the normal maintenance schedule of high priority maintenance activities. Complete high priority 2020 Field O&M Initiatives for: ITCTransmission (15) METC (13) ITC Midwest (10) Each target worth 5%. Payout reduced by 5% if not at or under Field O&M overall maintenance budget of $91.0M.	15 %	ITCTransmission and METC high priority initiatives not completed; ITC Midwest high priority initiatives completed under budget; All completed high priority Field O&M initiatives under budget of $91.0M	5%
	Capital Project Plan	Performing necessary system upgrades is critical to ensuring system reliability, providing a robust transmission grid and delivering financial performance.	Target is based on accrued capital investment. The maximum payout represents the risk-adjusted capital investment plan for 2020, with a threshold level also established. Complete $721M of the 2020 Capital Project Plan to achieve 30%; Complete $683M to achieve 15%.	15 - 30%	$938M	30%
				60 %		**45%**
Total Bonus (as a percent of target bonus level)				**100 %**		**85%**

(1) We utilize adjusted net income as a criterion in measuring achievement of financial goals for our annual corporate performance bonus. This non-GAAP financial measure reconciles to net income of our Regulated Operating Subsidiaries as follows:

(In millions of USD)	2020
Net Income of Regulated Operating Subsidiaries	$ 504
Adjustments Related to ROE Matters	(12)
Other Adjustments	4
Adjusted Net Income	$ 496

Additionally, our executives, including the NEOs, are eligible for an executive bonus multiplier. To further motivate management to provide value to the shareholder, we include a performance factor under which their ACPBs may be increased for outperformance by as much as 100% based on multiple measures, as follows:

Measure	**Threshold**	**Maximum**	**Achievement**	**Multiplier**	**Weight**	**Result**
Capital Project Plan	$759M	$820M	$938M	2.00x	30%	0.60x
Cash from Operations Pre-Working Capital	$669M	$703M	$680M	1.25x	25%	0.31x
Adjusted Consolidated Net Income (1)	$391M	$411M	$401M	1.50x	30%	0.45x
Inclusion & Diversity Plan	Create Plan	Level 2 Milestones	Level 2 Milestones	2.00x	15%	0.30x
Bonus Multiplier						**1.66x**

---

(1) We utilize adjusted consolidated net income as a criterion in measuring achievement of financial goals for the executive bonus multiplier. This non-GAAP financial measure reconciles to consolidated net income of ITC Holdings as follows:

(In millions of USD)	2020
Net Income	$ 407
Adjustments Related to ROE Matters	(12)
Other	6
Adjusted Consolidated Net Income	$ 401

Each measure has an established scale, which includes a threshold level and below equating to a 1.00x multiplier, having no impact on the bonus award, to a maximum of 2.00x, which would increase the bonus by 100%. Achievement against performance scales related to each of the above metrics produced an executive bonus multiplier of 1.66x. This performance factor was applied to each executive's ACPB factor of 85% to produce a final payment of approximately 141% of target.

Bonuses are based on a target bonus, which for each executive is a percentage of his or her base salary. The Committee considers each individual's job responsibilities and the results of its benchmarking analysis when determining the base bonus percentage for the executive officers, including the NEOs, which we refer to as the "target bonus levels". Target bonus levels for 2020 were 100% of base salary for each NEO. Mr. Oginsky received a prorated portion of the annual bonus based on his time employed by the Company in 2020.

Long-Term Incentive

The Committee provides and maintains a long-term equity incentive program under the 2017 Omnibus Plan, the Executive Omnibus Plan and the Fortis Inc. 2020 Restricted Share Unit Plan. In February 2020, the Committee approved grants of SBUs and PBUs to the NEOs, based on our CEO's recommendation (except for grants to the CEO), and also on the Committee's assessment of the performance of the Company and the executive. Award opportunities for the NEOs were provided in a mix of PBUs (weighted 67%) and SBUs (weighted 33%). The PBUs can be earned for results in two equally-weighted measures, Total Shareholder Return (relative to Fortis' peer group) and cumulative consolidated net income, over the three-year performance period. The PBU metrics were selected as Total Shareholder Return aligns with the Fortis shareholder experience and cumulative consolidated net income measures the sustained growth (organic and development), cost management and efficiency. Each unit is generally equivalent to one share of Fortis stock (as traded on the Toronto Stock Exchange) and earned PBU units are payable in cash and earned SBU units are payable in cash or Fortis common stock. Awards to the CEO were also presented to the Board of Directors by the Committee and ratified by the Board of Directors (other than the CEO). The amounts and more detailed terms of the 2020 SBU and PBU grants made under the Fortis Inc. 2020 Restricted Share Unit Plan and the Executive Omnibus Plan are described in the narrative following the Grants of Plan-Based Awards Table. The awards were designed to reward, motivate and encourage long-term performance, act as a retention mechanism, and further align the interests of the NEOs with the interests of the Fortis shareholder. Total value for the award for each grantee was determined based on a percentage of salary. For the NEOs, when the 2020 awards were made, the award values were targeted to be:

NEO	Grant Value Percent of Salary
Ms. Apsey	250 %
Ms. Holloway	175 %
Mr. Jipping	175 %
Ms. Mason Soneral	175 %
Ms. Tanner	175 %
Mr. Oginsky	175 %

In determining the size of grants under the long-term incentive program and the award mix, the Committee considered market practice, the recommendation of the CEO (with respect to grants other than to the CEO) in light of comparisons to benchmarking data, expense to the Company and the practice of other U.S. Fortis subsidiary companies.

Other Components of Our Executive Compensation Program

Pension Benefits. As is common in our industry and as established pursuant to our initial formation requirements included in the acquisition agreement with DTE Energy for ITCTransmission, we maintain a tax-qualified defined benefit retirement plan for eligible employees, comprised of a traditional pension component and a cash balance component. All employees, including the NEOs, participate in either the traditional component or the cash balance component. We have also established a supplemental nonqualified, noncontributory retirement benefit plan for selected management employees: the Executive Supplemental Retirement Plan, or ESRP, in which all of the NEOs participate. This plan provides for benefits that supplement those provided by our qualified defined benefit retirement plan. Benefits payable to the NEOs pursuant to the retirement plans are set by the terms of those plans. The Committee exercises no regular discretionary authority in the determination of benefits. The retirement plans may be modified, amended or terminated at any time, although no such action may reduce a NEO's earned benefits. See "Pension Benefits" for information regarding participation by the NEOs in our retirement plans as well as a description of the terms of the plans.

Benefits and Perquisites. The NEOs participate in a variety of benefit programs, which are designed to enable us to attract and retain our workforce in a competitive marketplace. These programs include our Savings and Investment Plan, which consists of an employee deferral contribution component and an employer safe-harbor matching contribution component.

Our NEOs are provided a limited number of perquisites in addition to benefits provided to our other employees. The purpose of these perquisites is to minimize distractions from the NEOs' attention to important Company initiatives, to facilitate their access to work functions and personnel, and to encourage interactions among NEOs and others within professional, business and local communities. NEOs are provided perquisites such as auto allowance, financial, estate and legal planning, income tax return preparation, annual physical, club memberships, and personal liability insurance. Additionally, we own aircraft to facilitate the business travel schedules of our executives and other employees, particularly to locations that do not provide efficient commercial flight schedules. Ms. Apsey and guests who travel with her are permitted to travel for personal business on our aircraft, with an annual maximum of 50 flight hours for such personal travel. Ms. Apsey incurs imputed income for all guests and herself for personal travel in the amount of the incremental cost to the Company of such travel.

We purchase tickets to various sporting, civic, cultural, charity and entertainment events. We use these tickets for business development, partnership building, charitable donations and community involvement. If not used for business purposes, we may make these tickets available to employees, including the NEOs, as a form of recognition and reward for their efforts. Because such tickets have already been purchased, we do not believe that there is any aggregate incremental cost to the Company, if a NEO uses a ticket for personal purposes.

None of the NEOs are reimbursed for income taxes associated with the value of the perquisites. The Committee continues to monitor and review the Company's perquisite program. Perquisites are further discussed in footnote 5 to the "Summary Compensation Table".

Potential Severance Compensation. Pursuant to their employment agreements, each NEO is entitled to certain benefits and payments upon a termination of his or her employment. Benefits and payments to be provided vary based on the circumstances of the termination. We believe it is important to provide these protections in order to ensure our NEOs will remain engaged and committed to us during an acquisition of the Company or other transition in management. See "Employment Agreements and Potential Payments Upon Termination or Change in Control" for further detail on these employment agreements, including a discussion of the compensation to be provided upon termination or a change in control.

Stock Ownership Policy

The Board believes that having a share ownership policy is a key element of strong corporate governance and aligns the interests of management with the interests of Fortis shareholders. Under these guidelines, which became effective January 1, 2020, officers, including NEOs, must achieve and maintain the applicable level of Fortis stock ownership by the fifth anniversary of when the guidelines first became applicable to the individual. The current levels are as follows:

Position	Ownership Level
Chief Executive Officer	2x annual base salary
Executive and Senior Vice Presidents	1.5x annual base salary
Vice Presidents	1x annual base salary

The securities that qualify for the purpose of determining compliance with the policy are common shares of Fortis stock and the executive's outstanding SBU awards. Share ownership levels include Fortis securities beneficially owned: (i) in a trust; (ii) by the executive's spouse; and (iii) by the executive's minor children. Any executive that fails to maintain minimum stock ownership under these guidelines, will not be eligible for future equity-based compensation awards until the later of (i) the end of the one-year period commencing on the date of such failure or (ii) such time as the executive is again in compliance with the guidelines. Each of the NEOs is in compliance with this policy.

Governance and Human Resources Committee Report

The Governance and Human Resources Committee has reviewed and discussed this Compensation Discussion and Analysis with management and, based on the review and discussions with management, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this report.

DEBORA M. FRODL   ALEXANDER I. GREENBAUM   DAVID G. HUTCHENS   A. DOUGLAS ROTHWELL

Summary Compensation

The following table provides a summary of compensation paid or accrued by the Company and its subsidiaries to or on behalf of the NEOs for services rendered by them during each of the last three calendar years, as required by SEC rules and regulations. The material terms of plans and agreements pursuant to which certain items set forth below were paid are discussed elsewhere in Compensation of Executive Officers and Directors.

Summary Compensation Table

Name	Year	Salary ($)	Stock Awards ($) (1)	Non-Equity Incentive Plan Compensation ($) (2)	Change in Pension Value & Non-qualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($) (4)	Total ($)
(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
Linda H. Apsey, President & CEO	2020	$ 819,630	$ 2,036,614	$ 1,151,376	$ 359,039	$ 84,625	$ 4,451,284
	2019	794,692	2,061,860	1,352,000	322,636	55,516	4,586,704
	2018	752,712	1,747,386	1,169,118	123,927	66,909	3,860,052
Gretchen L. Holloway SVP & CFO	2020	399,570	695,003	561,296	181,670	36,936	1,874,475
	2019	388,115	703,598	659,100	147,032	36,362	1,934,207
	2018	367,962	599,433	572,945	81,152	34,351	1,655,843
Jon E. Jipping, EVP & COO	2020	589,347	1,023,422	826,564	522,326	38,199	2,999,858
	2019	578,000	1,046,405	980,200	568,493	38,169	3,211,267
	2018	553,674	899,149	859,418	63,980	37,869	2,414,090
Christine Mason Soneral, SVP, General Counsel, Secretary & CCO	2020	396,285	688,169	555,793	200,948	35,950	1,877,145
	2019	389,469	703,598	659,100	170,742	36,500	1,959,409
	2018	377,204	612,373	585,333	66,424	35,250	1,676,584
Krista Tanner, SVP & CBUO	2020	339,797	593,288	479,176	123,653	34,620	1,570,534
Daniel J. Oginsky, Former EVP & CAO (5)	2020	252,759	847,330	—	23,000	1,662,596	2,785,685
	2019	483,988	875,001	819,650	236,208	36,742	2,451,589
	2018	466,685	758,200	724,698	51,865	36,556	2,038,004

(1) The amounts reported in this column represent the fair value of PBU awards and SBU awards granted to the NEOs under the 2017 Omnibus Plan, the Executive Omnibus Plan and the Fortis Inc. 2020 Restricted Share Unit Plan in accordance with FASB Accounting Standards Codification Topic 718, or ASC 718.

The grant date fair value of the SBU awards is based on the applicable share price on the grant date. The grant date fair value of the PBU awards is based on the applicable share price on the grant date and the payout of the performance (which approximates target achievement), and market conditions, with the market condition fair value determined using a Monte Carlo simulation valuation model. The SBU awards and PBU awards are liability awards, subject to remeasurement through the vesting date, and settled in cash, see "Grants of Plan-Based Awards." The value of the 2020 PBU awards at the grant date assuming that the highest level of performance conditions will be achieved are as follows:

Ms. Apsey	$ 2,715,447
Ms. Holloway	926,663
Mr. Jipping	1,364,526
Ms. Mason Soneral	917,538
Ms. Tanner	791,024
Mr. Oginsky	1,129,749

(2) The amounts reported in this column include cash awards tied to the achievement of annual Company performance goals under our annual corporate performance bonus plan in effect for each of 2020, 2019 and 2018. For information regarding the corporate goals for 2020, see "Compensation Discussion and Analysis -

Key Components of Our NEO Compensation Program - Annual Corporate Performance Bonus." Mr. Oginsky's 2020 bonus was prorated based on his time employed by the Company in 2020.

(3) All amounts reported in this column pertain to the tax-qualified defined benefit pension plan and the supplemental nonqualified, noncontributory retirement plan maintained by the Company. None of the income on nonqualified deferred compensation was above-market or preferential. Variations in the amounts from year to year reflect an additional year of service and pay changes used in the accrued benefit, as well as changes in assumptions on which the benefits are calculated, for which the formula has not been materially revised. The discount rate used for the present value of accumulated benefits was 4.39% in 2018, 3.44% in 2019 and 2.74% for 2020. The mortality assumption was changed from the Adjusted RP-2014 table projected for future mortality improvements with MP-2017 generational scale to the Pri-2012 tables with MP-2020 mortality improvement scale.

(4) All Other Compensation includes amounts for auto allowance, financial, estate and legal planning, income tax return preparation, annual physical, club memberships, event tickets, personal liability insurance, personal use of company aircraft and for other benefits such as Company contributions on behalf of the NEOs pursuant to the matching component of the Savings and Investment Plan. Perquisites have been valued for purposes of these tables on the basis of the aggregate incremental cost to the Company. The incremental cost of the personal use of the Company aircraft was determined based upon the Company's expenses incurred in connection with the actual costs of maintenance, landing, parking, crew and catering and estimated fuel costs relating to Ms. Apsey's hours of use of the aircraft. Fuel expense was determined by calculating the average fuel cost for the month and the average amount of fuel used per hour. These benefits and perquisites for 2020, 2019 and 2018 are itemized in the table below as required by applicable SEC rules.

Name	Year	401(k) Match	Personal Use of Company Aircraft	Other Benefits	Severance Payments	Total
Linda H. Apsey	2020	$ 17,100	$ 40,440	$ 27,085	$ —	$ 84,625
	2019	16,800	19,777	18,939	—	55,516
	2018	14,750	25,074	27,085	—	66,909
Gretchen L. Holloway	2020	15,450	—	21,486	—	36,936
	2019	15,100	—	21,262	—	36,362
	2018	14,750	—	19,601	—	34,351
Jon E. Jipping	2020	17,100	—	21,099	—	38,199
	2019	16,800	—	21,369	—	38,169
	2018	16,500	—	21,369	—	37,869
Christine Mason Soneral	2020	15,450	—	20,500	—	35,950
	2019	15,100	—	21,400	—	36,500
	2018	14,750	—	20,500	—	35,250
Krista Tanner	2020	14,120	—	20,500	—	34,620
Daniel J. Oginsky	2020	15,450	—	3,385	1,643,761	1,662,596
	2019	15,100	—	21,642	—	36,742
	2018	14,750	—	21,806	—	36,556

We purchase tickets to various sporting, civic, cultural, charity and entertainment events. We use these tickets for business development, partnership building, charitable donations and community involvement. If not used for business purposes, we may make these tickets available to employees, including the NEOs, as a form of recognition and reward for their efforts. Because such tickets have already been purchased, we do not believe that there is any aggregate incremental cost to the Company, if a NEO uses a ticket for personal purposes. The severance payments made to Mr. Oginsky include cash payments totaling $1,643,761, made up of (i) $259,898 paid as a prorated portion of his annual bonus, (ii) continuation of his base salary totaling $283,192, (iii) acceleration of SBUs totaling $337,849 (iv) $743,232 paid as a prorated portion of his PBU award, and (v) premiums for COBRA coverage totaling $19,590.

Table of Contents

(5) Mr. Oginsky's employment with the Company was terminated in May 2020.

Grants of Plan-Based Awards

The following table sets forth information concerning each grant of an award made to a NEO during 2020.

Name	Grant Date	Award Type	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Threshold ($)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Target ($)(1)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Maximum ($)(1)	Estimated Future Payouts Under Equity Incentive Plan Awards: Threshold (#)	Estimated Future Payouts Under Equity Incentive Plan Awards: Target (#)(2)	Estimated Future Payouts Under Equity Incentive Plan Awards: Maximum (#)(2)	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)(3)
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Linda H. Apsey	1/1/2020	SBU	$ —	$ —	$ —	—	—	—	16,367	$ 678,890
	1/1/2020	PBU	—	—	—	16,366	32,732	65,464	—	1,357,723
		ACPB	—	816,000	1,632,000	—	—	—	—	—
Gretchen L. Holloway	1/1/2020	SBU	—	—	—	—	—	—	5,585	231,671
	1/1/2020	PBU	—	—	—	5,585	11,170	22,340	—	463,332
		ACPB	—	397,800	795,600	—	—	—	—	—
Jon E. Jipping	1/1/2020	SBU	—	—	—	—	—	—	8,225	341,159
	1/1/2020	PBU	—	—	—	8,224	16,448	32,896	—	682,263
		ACPB	—	585,800	1,171,600	—	—	—	—	—
Christine Mason Soneral	1/1/2020	SBU	—	—	—	—	—	—	5,530	229,400
	1/1/2020	PBU	—	—	—	5,530	11,060	22,120	—	458,769
		ACPB	—	393,900	787,800	—	—	—	—	—
Krista Tanner	1/1/2020	SBU	—	—	—	—	—	—	4,768	197,777
	1/1/2020	PBU	—	—	—	4,768	9,535	19,070	—	395,512
		ACPB	—	339,600	679,200	—	—	—	—	—
Daniel J. Oginsky	1/1/2020	SBU	—	—	—	—	—	—	6,809	282,455
	1/1/2020	PBU	—	—	—	6,809	13,618	27,236	—	564,875
		ACPB	—	485,000	970,000	—	—	—	—	—

(1) The amount shown in Column (d) represents the potential payout for the ACPB based on "target bonus levels." The amount payable assuming maximum achievement of all bonus goals is set forth in column (e). Actual dollar amounts paid are disclosed and reported in the "Summary Compensation Table" as Non-Equity Incentive Plan Compensation. For more information regarding the ACPBs, see "Compensation Discussion and Analysis — Key Components of Our NEO Compensation Program — Annual Corporate Performance Bonus."

(2) Payment of each PBU award is contingent on meeting performance targets based on (1) Fortis Total Shareholder Return in comparison to the Total Shareholder Return during the performance period for each of the companies that comprise the 2020 Fortis peer group and (2) cumulative consolidated net income for each fiscal year during the performance period. The performance measures are independent of each other. If threshold, target or maximum performance goals are attained in the performance period, 50%, 100% or 200% of the target amount, respectively, may be earned. If actual performance falls between threshold, target and maximum, the awards would be prorated between levels based on performance outcome. For more information regarding performance share awards, see "Grant of Plan-Based Awards - Performance-Based Unit Award Agreements."

(3) Grant Date Fair Value consists of SBUs and PBUs awarded under the Fortis Inc. 2020 Restricted Share Unit Plan and Executive Omnibus Plan, respectively, with a grant date of January 1, 2020. The SBUs and PBUs reflected here are recorded at fair value at the date of grant, which was $41.48 per share. Share fair values were converted from Canadian Dollars to US Dollars using the "Award Conversion Rate" defined in the plans.

The Committee has established long-term incentive targets as a percentage of the base salary for each NEO in consideration of benchmarking data on total direct compensation, the importance of the NEO's position to the success of the Company, our need to create meaningful incentives to enhance performance and the culture of teamwork that makes our company successful. The Committee did not have a pre-established targeted allocation of total direct compensation.

The Committee had the power to award SBUs in the form of equity or cash under the Fortis Inc. 2020 Restricted Share Unit Plan and PBUs in the form of equity or cash under the Executive Omnibus Plan with the terms of each award set forth in a written agreement with the recipient. Grants made in 2020 to the NEOs were made under their respective plans pursuant to terms stated in the SBU and PBU award agreements.

Performance-Based Unit Award Agreements

The PBU award agreements entered into with each NEO on January 1, 2020 (the "PBU Grant Date") (each a "PBU Agreement") provide generally that the award will vest on January 1, 2023 (the "PBU Vesting Date") to the extent one or more of the performance goals are met and if the grantee continues to be employed by the Company through the PBU Vesting Date. One-half of the Target Number of PBUs shall be related to the Fortis Total Shareholder Return goal (the "TSR goal") and one-half of the Target Number of PBUs shall be related to the Cumulative Consolidated Net Income goal (the "CCNI goal"). The PBUs will become earned as set forth in the following table:

Measurement Category	Goal at Threshold	Shares at Threshold	Goal at Target	Shares at Target	Goal at Maximum	Shares at Maximum
Fortis Total Shareholder Return	30th percentile	50% of TSR Target Units	50th percentile	100% of TSR Target Units	85th percentile	200% of TSR Target Units
Cumulative Consolidated Net Income	99% of Target	50% of CCNI Target Units	100% of Target	100% of CCNI Target Units	102% of Target	200% of CCNI Target Units

The performance period for the award is January 1, 2020 through December 31, 2022 (the "Payment Criteria Period"). The performance measures are independent of each other; that is, if the threshold level of one performance measure is attained, units relating to that measure will be "earned" (subject to vesting as otherwise provided in the PBU Agreement) even if the threshold level of the other performance measure is not attained. The number of PBUs that are "earned" with respect to each performance measure will be prorated between levels based on performance. The Committee will have discretion to reduce the number of PBUs earned under certain circumstances.

Total Shareholder Return of Fortis will be compared to each of the companies (the "Peer Companies") listed in the Fortis Peer Group 2020 Report excluding any company that is no longer traded on the Toronto Stock Exchange or a "national securities exchange" at the end of the Payment Criteria Period. The Peer Companies currently consist of the following 25 U.S. and Canadian public utility companies:

Alliant Energy Corporation
Ameren Corporation
Atmos Energy Corporation
Canadian Utilities Limited
CenterPoint Energy Inc.
CMS Energy Corporation
Consolidated Edison Inc.
DTE Energy Company
Edison International
Emera Incorporated
Entergy Corporation
Evergy, Inc.
Eversource Energy
FirstEnergy Corp.
Hydro One Limited
NiSource Inc.
OGE Energy Corp.
PG&E Corporation
Pinnacle West Capital Corporation
PPL Corporation
Public Service Enterprise Group Inc.
Sempra Energy
UGI Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

The Total Shareholder Return of Fortis and the Peer Companies shall be computed in U.S. dollars as follows:

A: Calculate the Market Price as of the first day of the Payment Criteria Period (if necessary, converted into U.S. dollars based on the Award Conversion Rate as defined in the Executive Omnibus Plan)

B: Calculate the Market Price as of the last day of the Payment Criteria Period (if necessary, converted into U.S. dollars based on the Award Conversion Rate)

C: Calculate the total dividends paid per share of its common stock (or equivalent security) during the Payment Criteria Period (if necessary, converted into U.S. dollars based on the Award Conversion Rate)

Total Shareholder Return = ((B - A) + C)/A

Adjusted Consolidated Net Income for the Company for each calendar year in the Payment Criteria Period shall be equal to net income as set forth in the Company's audited consolidated financial statements contained in its annual report on Form 10-K for such year, as adjusted for extraordinary items and changes in Return on Equity, in each case in the Committee's discretion. Cumulative Consolidated Net Income for the Company during the Payment Criteria Period shall be the sum of the Adjusted Consolidated Net Income for each of the three years in the Payment Criteria Period.

If the grantee ceases to be employed before the PBU Vesting Date due to death, disability or "Retirement", and the grantee has been employed with the Company for 15 years or more, the grantee will receive, following the PBU Vesting Date, the number of PBUs to which the grantee would have otherwise been entitled if the grantee had remained employed through the PBU Vesting Date. If the grantee ceases to be employed before the PBU Vesting Date due to death, disability or Retirement, and the grantee has been employed with the Company for less than 15 years, the grantee will receive, following the PBU Vesting Date, (i) one-third of the number of PBUs to which the grantee would have otherwise been entitled if the grantee had remained an employee through the PBU Vesting Date shall be deemed to have vested on the PBU Vesting Date if termination occurred on or after the one-year anniversary of the PBU Grant Date and before the two-year anniversary of the PBU Grant Date, and (ii) two-thirds of the number of PBUs to which the grantee would have otherwise been entitled if the grantee had remained an employee through the PBU Vesting Date shall be deemed to have vested on the PBU Vesting Date if termination occurred one or after the two-year anniversary of the PBU Grant Date but before the PBU Vesting Date. If termination occurs prior to the PBU Vesting Date other than as a result of death, disability or Retirement, grantee will forfeit the award.

"Retirement" is defined to mean termination of grantee's employment with the Company upon or after completing 10 years of service with the Company after attaining the age of 45 if the grantee has provided the Company with at least six months' written notice of such retirement.

Upon a "Change of Control", as defined in the Executive Omnibus Plan, all outstanding PBUs become redeemable on the effective date of the consummation of the event resulting in the Change of Control (the "Change of Control Redemption Date"). In the event of a Change of Control, the payout percentage for outstanding PBUs is the product of (i) the higher of (A) 100% of the target number of PBUs in the award or (B) the actual payout percentage based on the Committee's assessment of performance of the payment criteria from the beginning of the Payment Criteria Period for the award through the date of the Change of Control, multiplied by (ii) a fraction, the numerator of which is the number of days elapsed in the Payment Criteria Period for the award through the date on which the Change of Control occurred and the denominator of which is the total number of days in the payment criteria period for the award.

Grantees are entitled to receive additional PBUs equal to the "dividend equivalent" when a cash dividend is paid on common shares of Fortis stock (each a "Common Share"). Such "dividend equivalent" shall be equal to a fraction where the numerator is the product of (a) the number of PBUs in the grantee's account on the date that the dividends are paid, including PBUs previously credited as "dividend equivalents," multiplied by (b) the dividend paid per Common Share and the denominator of which is the "Market Price" of one Common Share calculated on the date that dividends are paid, converted to U.S. dollars based on the Award Conversion Rate. All "dividend equivalent" PBUs shall have a PBU Vesting Date which is the same as the PBU Vesting Date for the PBUs in respect of which such additional PBUs are credited.

Service-Based Unit Award Agreements

The SBU award agreements entered into with each NEO on January 1, 2020 (the "SBU Grant Date") (each a "SBU Agreement") provide generally that, so long as the grantee remains employed by the Company, the SBUs fully vest upon the earlier of (i) January 1, 2023 (the "SBU Vesting Date") or (ii) the grantee's death, disability or "Retirement". If the grantee ceases to be employed before the SBU Vesting Date due to death, disability or Retirement, and the grantee has been employed with the Company for 15 years or more, the grantee will receive, the number of SBUs to which the grantee would have otherwise been entitled if the grantee had remained employed through the SBU Vesting Date. If the grantee ceases to be employed before the SBU Vesting Date due to death, disability or Retirement, and the grantee has been employed with the Company for less than 15 years, the grantee will receive a prorated number of SBUs to reflect the actual period between the SBU Grant Date and the date of the grantee's death, disability or Retirement. If termination occurs prior to the SBU Vesting Date other than as a result of death, disability or Retirement, grantee will forfeit the award.

Upon a "Change of Control", all outstanding SBUs become redeemable on the date that is immediately prior to the Change of Control Redemption Date.

"Retirement" and "Change of Control" are defined in the same manner as defined in the description of the PBU Agreement disclosed above. Grantees are entitled to receive additional dividend equivalent SBUs in the same manner as defined in the description of the PBU Agreement disclosed above.

The SBU Agreement provides that the grantee may elect to have their SBU awards vest as common shares of Fortis Inc. stock or cash payment. If the grantee does not satisfy their share holding requirement stated in the Stock Ownership Policy, 50% of the SBU awards must settle in common shares of Fortis Inc. stock.

Outstanding Equity Awards at Fiscal Year-End

The following table provides information with respect to SBUs and PBUs that have not vested as of the end of 2020 held by the NEOs.

Name	Number of Shares or Units of Stock That Have Not Vested (#) (SBUs)	Market Value of Shares or Units of Stock That Have Not Vested ($) (SBUs) (1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (PBUs)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (PBUs) (1)
(a)	(b)	(c)	(d)	(e)
Linda H. Apsey	21,432 (2)	$ 874,897	42,865 (3)	$ 3,499,470
	16,967 (4)	692,621	33,934 (5)	2,770,369
Gretchen L. Holloway	7,314 (2)	298,544	29,254 (3)	1,194,174
	5,790 (4)	236,357	23,160 (5)	945,405
Jon E. Jipping	10,877 (2)	444,014	43,506 (3)	1,775,971
	8,527 (4)	348,059	34,104 (5)	1,392,125
Christine Mason Soneral	7,314(2)	298,544	29,254 (3)	1,194,174
	5,733 (4)	234,040	22,932 (5)	936,095
Krista Tanner	4,353 (2)	177,702	17,413 (3)	710,805
	4,943 (4)	201,777	19,770 (5)	807,022
Daniel J. Oginsky	—	—	12,128 (3)	495,065

(1) Value was determined by multiplying the number of units that have not vested by the closing price of Fortis common stock on the NYSE as of December 31, 2020 ($40.82).

(2) These unvested SBUs were granted in 2019 and generally vest on December 31, 2021. These SBU numbers include the original SBU grant plus dividend equivalent units earned.

(3) These unvested PBUs were granted in 2019 and generally vest on December 31, 2021. These PBU numbers include the original PBU grant plus dividend equivalent units earned. The award contains

performance conditions established by the Committee. In order for PBUs to vest such performance conditions must be achieved. Amounts reported reflect PBU payouts as if the maximum performance goals have been achieved. Mr. Oginsky's PBUs were prorated on the date of the termination of his employment with the Company and remain outstanding until performance conditions are achieved.

(4) These unvested SBUs were granted in 2020 and generally vest on January 1, 2023. These SBU numbers include the original SBU grant plus dividend equivalent units earned.

(5) These unvested PBUs were granted in 2020 and generally vest on January 1, 2023. These PBU numbers include the original PBU grant plus dividend equivalent units earned. The award contains performance conditions established by the Committee. In order for PBUs to vest such performance conditions must be achieved. Amounts reported reflect PBU payouts as if the maximum performance goals have been achieved.

Equity grants made to NEOs in 2019 were made pursuant to the 2017 Omnibus Plan. The PBU grants made to NEOs in 2020 were made pursuant to the Executive Omnibus Plan and the SBU grants made to NEOs in 2020 were made pursuant to the Fortis Inc. Restricted Share Unit Plan. The terms of the grants are described above in the narrative discussion accompanying the "Grants of Plan-Based Awards" Table.

In February 2019, Mr. Jipping entered into a letter agreement with the Company amending his employment agreement and long-term incentive awards, including his SBU and PBU awards granted under the 2017 Omnibus Plan. Under the terms of the letter agreement upon Mr. Jipping's voluntary termination of employment, his SBU and PBU awards, which would otherwise be forfeited, will continue to vest on their normal schedule even if Mr. Jipping does not meet the retirement age, as defined in the 2017 Omnibus Plan, for continued vesting at the time of his termination. The letter agreement also removes Section 7c(ii)(B) of Mr. Jipping's employment agreement which defines his rights to terminate the employment agreement if his job responsibilities and authority were substantially diminished.

Option Exercises and Stock Vested

The following table provides information with respect to SBUs and PBUs held by the NEOs that vested during 2020:

	Stock Awards	
Name	**Number of Shares or Units of Stock Acquired on Vesting (#)**	**Value of Shares or Units of Stock Realized on Vesting ($) (1)**
(a)	(b)	(c)
Linda H. Apsey	19.032 (2)	$ 793,001
	61,664 (3)	2,569,323
Gretchen L. Holloway	6,529 (2)	272,051
	21,153 (3)	881,369
Jon E. Jipping	9,793 (2)	408,054
	31,730 (3)	1,322,093
Christine Mason Soneral	6,670 (2)	272,260
	21,610 (3)	900,422
Krista Tanner	1,705 (2)	71,023
	5,521 (3)	230,035
Daniel J. Oginsky	8,380 (4)	337,849 (4)
	17,838 (3)	743,232

(1) Value is based on the 5-day VWAP price of common stock on the TSX on the vesting date, converted from Canadian Dollars to US Dollars using the "Award Conversion Rate" defined in the 2017 Omnibus Plan, which is $41.6667.

(2) Amounts reported reflect the vesting of SBUs granted March 7, 2018 and associated dividend equivalent units.

(3) Amounts reported reflect the vesting of PBUs granted March 7, 2018 and associated dividend equivalent

units. The award contains performance conditions established by the Committee. The performance period ended on December 31, 2020. The Committee certified the achievement of 162% of the applicable performance goals on February 2, 2021. Amount for Mr. Oginsky is prorated based on his termination date.

(4) Amounts reported reflect the prorated vesting of SBUs granted March 7, 2018 and March 6, 2019, and associated dividend equivalent units, that vested upon Mr. Oginsky's termination of employment with the Company. The value is based on the 5-day VWAP price of common stock on the TSX on the vesting date, converted from Canadian Dollar to US Dollars using the "Award Conversion Rate" defined in the 2017 Omnibus Plan.

Pension Benefits

The following table provides information with respect to each pension benefit plan that provides for payments or other benefits at, following or in connection with retirement. Those plans are the International Transmission Company Retirement Plan (the "Qualified Plan") and the ESRP.

Pension Benefits Table

Name	Plan Name	Number of Years Credited Service (#)(1)	Present Value of Accumulated Benefit ($)(2)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
Linda H. Apsey	Cash Balance Component	26.58	$ 467,421	N/A
	ESRP Shift	N/A	39,359	N/A
	Total Qualified Plan		**506,780**	N/A
	ESRP	17.83	2,131,664	N/A
Gretchen Holloway	Cash Balance Component	16.95	327,627	N/A
	Total Qualified Plan		**327,627**	N/A
	ESRP	5.91	418,557	N/A
Jon E. Jipping	Traditional Component	30.03	2,075,036	N/A
	Total Qualified Plan		**2,075,036**	N/A
	ESRP	15.92	1,693,928	N/A
Christine Mason Soneral	Cash Balance Component	13.29	319,719	N/A
	Total Qualified Plan		**319,719**	N/A
	ESRP	13.28	825,637	N/A
Krista Tanner	Cash Balance Component	6.14	136,977	N/A
	Total Qualified Plan		**136,977**	N/A
	ESRP	6.14	281,183	N/A
Daniel J. Oginsky	Cash Balance Component	15.58	393,485	N/A
	Total Qualified Plan		**393,485**	N/A
	ESRP	15.58	1,173,054	N/A

(1) Credited service is estimated as of December 31, 2020 and represents the service reflected in the determination of benefits. For determining vesting, service with DTE Energy is counted for the Qualified Plan only.

For Ms. Apsey and Mr. Jipping, the credited service for the cash balance and traditional components of the Qualified Plan, respectively, includes service with DTE Energy. The Company began operations on February 28, 2003, following its acquisition of ITCTransmission from DTE Energy. As of that date, the benefits from DTE Energy's qualified plan that had accrued, as well as the associated assets from DTE Energy's pension trust, were transferred to the Qualified Plan. Therefore, even though DTE Energy service is included in determining the benefits under the traditional and cash balance components of the Qualified Plan, the benefits associated with this additional service do not represent a benefit augmentation, but rather a transfer of benefit liability and associated assets from DTE Energy's qualified plan to the Qualified Plan. With respect to the ESRP, credited service includes Company service only for the period during which the NEO was an ESRP participant.

(2) The “Present Value of Accumulated Benefit” is the estimated lump-sum equivalent value measured as of December 31, 2020 (the “measurement date” used for financial accounting purposes) of the benefit that was earned as of that date. Certain benefits are payable as an annuity only, not as a lump sum, and/or may not be payable for several years in the future. The values reflected are based on several assumptions. The date at which the present values were estimated was December 31, 2020. The rate at which future expected benefit payments were discounted in calculating present values was 2.74%, the same rate used for fiscal year-end 2020 financial accounting disclosure of the Qualified Plan. The future annual earnings rate on account balances under the cash balance and ESRP shift components of the Qualified Plan, and for ESRP benefits, was assumed to be 1.42% for 2021 and 4.00% thereafter.

We assumed no NEOs would die or become disabled prior to retirement or terminate employment with us prior to becoming eligible for benefits unreduced for early retirement. The assumed retirement age for each executive was generally the earliest age at which benefits unreduced for early retirement were available under the respective plans. For the traditional component of the defined benefit plan, that age is the earlier of (1) age 58 with 30 years of service (including service with DTE Energy), or (2) age 60 with 15 years of service. For consistency, we generally use the same assumed retirement commencement age for other benefits, including benefits expressed as an account value where the concept of benefit reductions for early retirement is not meaningful. The assumed retirement benefit commencement ages were 58 for each NEO, except that Mr. Oginsky’s ESRP benefit will be paid in a lump sum on March 1, 2021.

Post-retirement mortality was assumed to be in accordance with the Pri-2012 mortality table projected for future mortality improvements with MP-2020 generational scale. Benefits under the traditional component of the Qualified Plan were assumed to be paid as a monthly annuity payable for the lifetime of the employee. For all other benefits, payment was assumed to be as a single lump sum, although other actuarially equivalent forms are available.

We maintain one tax-qualified noncontributory defined benefit pension plan and one supplemental nonqualified, noncontributory defined benefit retirement plan. First, we maintain the Qualified Plan, which provides funded, tax-qualified benefits up to the limits on compensation and benefits under the Internal Revenue Code. Generally, all of our salaried employees, including the NEOs, are eligible to participate.

We maintain the ESRP, in which all of our NEOs participate. The ESRP provides additional retirement benefits which are not tax qualified.

The following describes the Qualified Plan and the ESRP, and pension benefits provided to the NEOs under those plans.

Qualified Plan

There are two primary retirement benefit components of the Qualified Plan. Each NEO earns benefits from the Company under only one of these primary components.

Because our first operating utility subsidiary was acquired from DTE Energy, a component of the Qualified Plan bears relation to the DTE Energy Corporation Retirement Plan (the “DTE Plan”). Generally, persons who were participants in the “traditional component” of the DTE Plan as of February 28, 2003 (the date ITCTransmission was acquired from DTE Energy) earn benefits under the traditional component of our Qualified Plan. All other participants earn benefits under the cash balance component. Ms. Apsey also has benefits under the ESRP shift described below.

Benefits under the Qualified Plan are funded by an irrevocable tax-exempt trust. A NEO’s benefit under the Qualified Plan is payable from the assets held by the tax-exempt trust.

NEOs become fully vested in their normal retirement benefits described below with 3 years of service, including service with DTE Energy, or upon attainment of the plan’s normal retirement age of 65. If a NEO terminates employment with less than 3 years of service, the NEO is not vested in any portion of his or her benefit.

Traditional Component of Qualified Plan

Mr. Jipping participates in the traditional component of the Qualified Plan. The benefits are determined under the following formula, stated as an annual single life annuity payable in equal monthly installments at the normal retirement age of 65: 1.5% times average final compensation times credited service up to 30 years, plus 1.4% times average final compensation times credited service in excess of 30 years. Credited service includes service with DTE Energy. Although benefits under the formula are defined in terms of a single life annuity, other annuity forms (e.g., joint and survivor benefits) are available that have the same actuarial value as the single life annuity benefit. The benefits are not payable in the form of a lump sum.

Average final compensation is equal to one-fifth of the NEO's salary (excluding any bonuses or special pay) during the 260 weeks of credited service, not necessarily consecutive, at any time during the NEO's employment that results in the highest average.

Benefits provided under the Qualified Plan are based on compensation up to a compensation limit under the Internal Revenue Code (which was $285,000 in 2020 and is indexed in future years). In addition, benefits provided under the Qualified Plan may not exceed a benefit limit under the Internal Revenue Code (which was $230,000 payable as a single life annuity beginning at normal retirement age in 2020).

NEOs may retire with a reduced benefit as early as age 45 after 15 years of credited service. If a NEO has 30 years of credited service at retirement, the benefit that would be payable at normal retirement age is reduced for commencement ages below 58. The percentage of the normal retirement benefit payable at sample commencement ages is as follows:

Age 58 and older:	100%
Age 55:	85%
Age 50:	40%

If a NEO has less than 30 years but more than 15 years of credited service at retirement, the benefit that would be payable at normal retirement age is reduced for commencement ages below age 60. The percentage of the normal retirement benefit payable at sample commencement ages is as follows:

Age 60 and older:	100%
Age 55:	71%
Age 50:	40%

If a NEO terminates employment prior to earning 15 years of credited service, the annuity benefit may not commence prior to attaining age 65. If the NEO terminates employment after earning 15 years of credited service but below age 45, the benefit may commence as early as age 45. The percentage of the normal retirement benefit payable at sample commencement ages is as follows:

Age 65 and older:	100%
Age 60:	58%
Age 55:	36%
Age 50:	23%

Mr. Jipping's annual accrued benefit payable in monthly installments as an annuity for his lifetime, beginning at age 60, is approximately $124,000. He is fully vested.

Cash Balance Component of Qualified Plan

Mses. Apsey, Holloway, Mason Soneral and Tanner participate in the cash balance component of the Qualified Plan. The benefits are stated as a notional account value.

Each year, a NEO's account is increased by a "contribution credit" equal to 7% of pay. For this purpose, pay is equal to base salary plus bonuses and overtime up to the same compensation limit as applies under the traditional component of the Qualified Plan ($285,000 in 2020). Each year, a NEO's account is also increased by an "interest credit" based on 30-year Treasury rates.

Upon termination of employment, a vested NEO may elect full payment of his or her account. Alternate forms of benefit (e.g., various forms of annuities) are available as well that have the same actuarial value as the account.

Mses. Apsey, Holloway, Mason Soneral and Tanner are entitled to immediate payment of their account value on termination of employment, even if before normal retirement age. Ms. Apsey's estimated account value as of year-end 2020 is approximately $440,000, Ms. Holloway's is approximately $291,000, Ms. Mason Soneral's is approximately $291,000, Ms. Tanner is approximately $122,000. Mr. Oginsky is entitled to receive a payment equal to his account value of $355,000 in connection with the termination of his employment in May 2020.

The ESRP provides notional account accruals similar to the cash balance component of the Qualified Plan. The "compensation credit" to the NEO's notional account, analogous to the contribution credit in the cash balance component of the Qualified Plan, is equal to 9% of base salary plus actual bonus earned under the Company's annual bonus plan. The "investment credit," analogous to the interest credit in the cash balance component of the Qualified Plan, is similarly based on 30-year Treasury rates.

The ESRP shift benefit is an amount that would otherwise be payable from the ESRP, but is instead being paid from the Qualified Plan, subject to applicable qualified plan legal limits on the ability to discriminate in favor of highly paid employees. The NEO's cash balance account is increased by any amounts shifted from the ESRP. The purpose of the benefit is to provide the NEO and the Company the tax advantages of providing benefits through a tax qualified plan.

Ms. Apsey has received ESRP shift additions to her Qualified Plan cash balance account. There was no shift of compensation credits for 2020, although previous shifts have continued to earn interest credits. As of year-end 2020, her ESRP shift balance was approximately $37,000.

Executive Supplemental Retirement Plan

The ESRP is a nonqualified retirement plan. Only selected executives participate, including all our NEOs. The purpose of the ESRP is to promote the success of the Company and its subsidiaries by providing the ability to attract and retain talented executives by providing such designated executives with additional retirement benefits.

The ESRP resembles the cash balance component of the Qualified Plan in that benefits are expressed as a notional account value and the vested account balance is payable as a lump sum on termination of employment, although an installment option of equivalent value is also available.

Each year, a NEO's account is increased by a "compensation credit" equal to 9% of pay. For this purpose, pay is equal to base salary plus any bonus under the Company's annual corporate performance bonus plan. There is no limit on compensation that may be taken into account as in the Qualified Plan. Each year, a NEO's account is also increased by an "investment credit" equal to the same earnings rate as the interest credit in the cash balance component of the Qualified Plan, based on 30-year Treasury rates.

The plan has been in effect since March 1, 2003. Vesting occurs at 20% for each year of participation. All of our NEOs are fully vested.

As noted above in the description of the Qualified Plan, a portion of the ESRP account balance may be shifted to the cash balance component of the Qualified Plan each year, as permitted under the rules for qualified plans. Such a shift allows the NEOs to become immediately vested in the account values shifted and confers certain tax advantages to the NEOs and us. As of December 31, 2020, the ESRP account values, net of the amounts shifted to the Qualified Plan, are as follows:

Ms. Apsey	$	2,007,114
Ms. Holloway		371,553
Mr. Jipping		1,671,249
Ms. Mason Soneral		749,482
Ms. Tanner		251,388
Mr. Oginsky		1,173,054

The ESRP is funded with a Rabbi Trust, which we cannot use for any purpose other than to satisfy the benefit obligations under the ESRP, except in the event of the Company's bankruptcy, in which case the assets are available to general creditors.

Nonqualified Deferred Compensation

We maintain the Executive Deferred Compensation Plan under which nonqualified deferred compensation is permissible. Only selected officers of the Company, including the NEOs, are eligible to participate in this plan. NEOs are allowed to defer up to 100% of their salary and bonus. Investment earnings are based on the various investment options available under the plan and are selected by the individual NEOs. Distributions will generally be made at the NEO's termination of employment for any reason. Mr. Jipping elected to participate in 2019 and his deferral was withheld in 2020. Mr. Jipping also elected to participate in 2020, and his deferral will be made in 2021 due to his 2020 bonus payment occurring in 2021. Mr. Jipping is the only NEO that participated in the Executive Deferred Compensation Plan in 2020.

Employment Agreements and Potential Payments Upon Termination or Change in Control

Employment Agreements

As referenced above, we entered into employment agreements with Ms. Apsey and Mr. Jipping in December 2012 which superseded the employment agreements then in effect. In February 2015, we entered into an employment agreement with Ms. Mason Soneral which superseded her employment agreement then in effect. In July 2017, we entered into an employment agreement with Ms. Holloway, which superseded her employment agreement then in effect. In February 2019, we entered into an employment agreement with Ms. Tanner which superseded her employment agreement then in effect. Each employment agreement is subject to automatic one-year employment term renewals each year beginning on its second anniversary, unless either party provides the other with 30 days' advance written notice of intent not to renew the employment term. Ms. Apsey's agreement was modified in October 2016 in connection with her appointment as President and Chief Executive Officer and the initial term of the agreement expired on December 31, 2018 but is subject to the automatic one-year renewal provision described above. The following describes the material terms of the employment agreements, as amended, with the NEOs who remained employed by the Company on December 31, 2020.

The employment agreements provide that each NEO will receive an annual base salary equal to their current base salary, which is subject to annual review and increase by our Board of Directors at its discretion. The employment agreements also provide that NEOs are eligible to receive an annual cash bonus, subject to our achievement of certain performance targets established by our Board of Directors, as detailed in "Compensation Discussion and Analysis." The employment agreements also provide the NEOs with the right to participate in equity plans, employee benefit plans and retirement plans, including but not limited to welfare plans, retiree welfare benefit plans and defined benefit and defined contribution plans.

In addition, the NEOs' employment agreements provide for payments by us of certain benefits upon termination of employment. The rights available at termination depend on the situation and circumstances surrounding the terminating event. The terms "Cause" and "Good Reason" are used in the employment agreements of each NEO and an understanding of these terms is necessary to determine the appropriate rights for which a NEO is eligible. The terms are defined as follows:

- *Cause* means: a NEO's continued failure substantially to perform his or her duties (other than as a result of total or partial incapacity due to physical or mental illness) for a period of 10 days following written notice by the Company to the NEO of such failure; dishonesty in the performance of the NEO's duties; a NEO's conviction of, or plea of nolo contender to, a crime constituting a felony or misdemeanor involving moral turpitude; willful malfeasance or willful misconduct in connection with a NEO's duties; any act or omission which is injurious to the financial condition or business reputation of the Company; or violation of the non-compete or confidentiality provisions of the employment agreement.
- *Good reason* means: a greater than 10% reduction in the total value of the NEO's base salary, target bonus, and employee benefits; or if the NEO's responsibilities and authority are substantially diminished.

If a NEO's employment is terminated with cause by the Company or by the NEO without good reason, the NEO will generally only receive his or her accrued but unpaid compensation and benefits as of the date of his or her employment termination. If the NEO terminates due to death or disability (as defined in the employment agreements), the NEO (or the NEO's spouse or estate) would also receive a pro rata portion of his or her current year annual target bonus.

If a NEO's employment is terminated by the Company without cause or by the NEO for good reason, the NEO will receive the following, subject to the NEO's execution of a release agreement and commencing generally on the earliest date that is permitted under Section 409A of the Internal Revenue Code:

- any accrued but unpaid compensation and benefits including:
    - Ms. Apsey: cash balance and ESRP shift under the Qualified Plan and vested portion of ESRP balance;
    - Mr. Jipping: annual benefit under the traditional component of the Qualified Plan and vested portion of ESRP balance; and
    - Ms. Mason Soneral, Ms. Holloway and Ms. Tanner: cash balance under the Qualified Plan and vested portion of ESRP balance
- continued payment of the NEO's then-current base salary for two years;
- if the termination is within six months before or two years after a "Change of Control" (as defined in the employment agreements), payment of an amount equal to two times the average of the ACPBs, that were payable to the NEO for the three fiscal years immediately preceding the fiscal year in which his or her employment terminates, payable in equal installments over the period in which continued base salary payments are made;
- a pro rata portion of the ACPB for the year of termination, based upon the Company's actual achievement of the performance targets for such year as determined under the annual corporate performance bonus plan and paid at the time that such bonus would normally be paid;
- eligibility to continue coverage under our active medical, dental and vision plans subject to applicable COBRA rules; if such coverage is elected, we will reimburse the NEO for the shorter of 18 months, or until the NEO becomes eligible for coverage under another employer-sponsored group plan, in an amount equal to our periodic cost of such coverage for other executives, plus a tax gross-up amount;
- outplacement services for up to two years; and
- for Ms. Apsey, deemed satisfaction of the eligibility requirements of our Postretirement Welfare Plan for purposes of participation therein; and for Mr.Jipping, participation in our Postretirement Welfare Plan only if, by the end of their specified severance period, he has achieved the necessary age and service credit otherwise necessary to meet the eligibility requirements. In addition, if we terminate our Postretirement Welfare Plan and, by application of the provisions described in the prior sentence, any of these NEOs would otherwise be entitled to retiree welfare benefits, we will establish other coverage for the NEO or the NEO will receive a cash payment equal to our cost of providing such benefits, in order to assist the NEO in obtaining other retiree welfare benefits.

In addition, while employed by us and for a period of two years after any termination of employment without cause by the Company (other than due to their disability) or for good reason by them and for a period of one year following any other termination of their employment, the NEOs will be subject to certain covenants not to compete with or assist other entities in competing with our business and not to encourage our employees to terminate their employment with us. At all times while employed and thereafter, all of the NEOs will also be subject to a covenant not to disclose confidential information.

In the event the NEO becomes subject to excise taxes under Section 4999 of the Internal Revenue Code as a result of payments and benefits received under the employment agreements or any other plan, arrangement or agreement with us, we will pay the NEO only that portion of such payments which are in total equal to one dollar less than the amount that would subject the NEO to the excise tax.

Payments in the Event of Termination

The benefits to be provided to the NEOs as a result of termination under various scenarios are detailed in the tables below. The tables assume that the termination occurred on December 31, 2020.

Linda H. Apsey - Termination Scenarios: Value of Potential Payments

Total Value of Severance, Benefits and Unvested Equity Awards(1)(2)

	Voluntary Resignation	Involuntary For Cause	Involuntary Not-for-Cause or Voluntary Good Reason	Change In Control (pre-tax)(3)	Disability	Death (pre-retirement)(4)
Compensation						
Cash Severance	$ —	$ —	$ 1,632,000	$ 4,116,287	$ —	$ —
Target Short-term Bonus	—	—	—	—	816,000	816,000
Pro Rata Short-term (Annual) Incentive Comp	—	—	1,151,376	1,151,376	—	—
Retention Awards			—	—	—	—
Service-Based Unit Awards (5)	—	—	291,622	1,651,740	1,651,740	1,651,740
Performance-Based Unit Awards (6)	—	—	583,245	1,628,218	3,134,919	3,134,919
Benefits and Perquisites			—			
Retirement Plan	—	—	—	—	—	—
ESRP	—	—	—	—	—	—
Perquisites	—	—	25,000	25,000	—	—
Health & Welfare Benefits	—	—	31,733	31,733	—	—
Postretirement Welfare Plan (7)	—	—	848,541	848,541	—	—
Total Payout:	$ —	$ —	$ 4,563,517	$ 9,452,895	$ 5,602,659	$ 5,602,659

Gretchen L. Holloway - Termination Scenarios: Value of Potential Payments

Total Value of Severance, Benefits and Unvested Equity Awards(1)(2)

	Voluntary Resignation	Involuntary For Cause	Involuntary Not-for-Cause or Voluntary Good Reason	Change In Control (pre-tax)(3)	Disability	Death (pre-retirement)(4)
Compensation						
Cash Severance	$ —	$ —	$ 795,600	$ 2,004,880	$ —	$ —
Target Short-term Bonus	—	—	—	—	397,800	397,800
Pro Rata Short-term (Annual) Incentive Comp	—	—	561,296	561,296	—	—
Service-Based Unit Awards (5)	—	—	499,515	565,071	565,071	565,071
Performance-Based Unit Awards (6)	—	—	199,029	555,626	1,069,790	1,069,790
280G Cutback	—	—	—	(828,134)	—	—
Benefits and Perquisites						
Retirement Plan	—	—	—	—	—	—
ESRP	—	—	—	—	—	—
Perquisites	—	—	25,000	25,000	—	—
Health & Welfare Benefits	—	—	10,787	10,787	—	—
Total Payout:	$ —	$ —	$ 2,091,227	$ 2,894,526	$ 2,032,661	$ 2,032,661

Table of Contents

Jon E. Jipping - Termination Scenarios: Value of Potential Payments

Total Value of Severance, Benefits and Unvested Equity Awards(1)(2)

	Voluntary Resignation or Voluntary Good Reason	Involuntary For Cause	Involuntary Not-for-Cause	Change In Control (pre-tax)(3)	Disability	Death (pre-retirement)(4)
Compensation						
Cash Severance	$ —	$ —	$ 1,171,600	$ 2,990,971	$ —	$ —
Target Short-term Bonus	—	—	—	—	585,800	585,800
Pro Rata Short-term (Annual) Incentive Comp	—	—	826,564	826,564	—	—
Service-Based Unit Awards (5)	843,749	—	148,005	843,749	843,749	843,749
Performance-Based Unit Awards (6)	—	—	295,995	824,011	1,584,048	1,584,048
Benefits and Perquisites						
Retirement Plan	—	—	—	—	—	—
ESRP	—	—	—	—	—	—
Perquisites	—	—	25,000	25,000	—	—
Health & Welfare Benefits	—	—	25,137	25,137	—	—
Postretirement Welfare Plan (7)	—	—	874,856	874,856		
Total Payout:	$ 843,749	$ —	$ 3,367,157	$ 6,410,288	$ 3,013,597	$ 3,013,597

Christine Mason Soneral - Termination Scenarios: Value of Potential Payments

Total Value of Severance, Benefits and Unvested Equity Awards(1)(2)

	Voluntary Resignation	Involuntary For Cause	Involuntary Not-for-Cause or Voluntary Good Reason	Change In Control (pre-tax)(3)	Disability	Death (pre-retirement)(4)
Compensation						
Cash Severance	$ —	$ —	$ 787,000	$ 2,021,964	$ —	$ —
Target Short-term Bonus	—	—	—	—	393,900	393,900
Pro Rata Short-term (Annual) Incentive Comp	—	—	555,793	555,793	—	—
Service-Based Unit Awards (5)	—	—	99,515	570,827	570,827	570,827
Performance-Based Unit Awards (6)	—	—	199,029	554,074	1,065,135	1,065,135
Benefits and Perquisites						
Retirement Plan	—	—	—	—	—	—
ESRP	—	—	—	—	—	—
Perquisites	—	—	25,000	25,000	—	—
Health & Welfare Benefits	—	—	24,793	24,793	—	—
Total Payout:	$ —	$ —	$ 1,691,130	$ 3,752,451	$ 2,029,862	$ 2,029,862

Table of Contents

Krista Tanner - Termination Scenarios: Value of Potential Payments

Total Value of Severance, Benefits and Unvested Equity Awards(1)(2)

	Voluntary Resignation	Involuntary For Cause	Involuntary Not-for-Cause or Voluntary Good Reason	Change In Control (pre-tax)(3)	Disability	Death (pre-retirement)(4)
Compensation						
Cash Severance	$ —	$ —	$ 679,200	$ 1,172,021	$ —	$ —
Target Short-term Bonus	—	—	—	—	339,600	339,600
Pro Rata Short-term (Annual) Incentive Comp	—	—	479,176	479,176	—	—
Service-Based Unit Awards (5)	—	—	59,234	247,288	247,288	247,288
Performance-Based Unit Awards (6)	—	—	118,468	371,439	758,914	758,914
280G Cutback	—	—	—	(415,126)	—	—
Benefits and Perquisites						
Retirement Plan	—	—	—	—	—	—
ESRP	—	—	—	—	—	—
Perquisites	—	—	25,000	25,000	—	—
Health & Welfare Benefits	—	—	20,545	20,545	—	—
Total Payout:	$ —	$ —	$ 1,381,623	$ 1,900,343	$ 1,345,802	$ 1,345,802

(1) All scenarios include the value of severance. For Ms. Apsey and Mr. Jipping, the value of the Postretirement Welfare Plan is additionally included where applicable. The Pension Benefits Table assumes that none of the NEOs are terminated prior to retirement age and that benefits are paid once retirement commences (age 58 is assumed). All other accrued pension benefits, outside of present value reductions outlined in footnote (5), and additional pension benefits upon death, have not been included in these termination scenarios but can be found in the “Pension Benefits Table”.

(2) Upon any termination of employment, benefits that are accrued but unpaid prior to that event are paid. These benefits are assumed to be $0 in the above tables.

(3) Change in control values include severance amounts reflecting cutbacks to the extent employer payments exceed the executive respective limits. Ms. Holloway and Ms. Tanner would be subject to an excise tax on the employer payments as of the assumed change in control date; therefore, cutbacks in the amounts of $828,134 (Ms. Holloway) and $415,126 (Ms. Tanner) have been reflected.

(4) In the event of Mr. Jipping’s termination for death (pre-retirement), his spouse would receive half the 50% joint and survivor annuity under the traditional component of the Qualified Plan. Under termination for death (pre-retirement), Ms. Apsey’s, Ms. Mason Soneral’s, Ms. Holloway’s and Ms. Tanner’s Qualified Plan benefits are payable immediately to the surviving spouse (if any) and ESRP benefits are payable to a designated beneficiary. The above termination scenarios do not reflect the reduction in present value of death benefits ($154,161 for Ms. Apsey, $83,796 for Ms. Holloway, $1,045,683 for Mr. Jipping, $105,645 for Ms. Mason Soneral and $44,310 for Ms. Tanner compared to present value in the Pension Benefits Table).

(5) Under the 2017 Omnibus Plan, outstanding and unvested SBUs and respective dividend equivalents shall be deemed to be vested SBUs and redeemable on the Change of Control Redemption Date (as defined in the 2017 Omnibus Plan). In the case of Death or Disability (each as defined in the 2017 Omnibus Plan) termination, outstanding and unvested SBUs and respective dividend equivalents shall be deemed to be vested SBUs and redeemable on the date of the death or on the date on which the grantee’s service is terminated due to Disability. In the case of Retirement or Involuntary Termination Without Cause (each as defined in the 2017 Omnibus Plan) within one year of the grant date, outstanding and unvested SBUs and respective dividend equivalents shall be deemed to be forfeited. If Retirement or Involuntary Termination Without Cause occurs one year or more after the grant date,

SBUs and respective dividend equivalents shall be deemed to have vested pro-rata based on the period served from the grant date to termination. For Mr. Jipping, pursuant to the Jipping Letter Agreement, upon a voluntary termination of employment, his SBUs, which would otherwise be forfeited, will continue to vest on their normal schedule. Under the Fortis Inc. 2020 Restricted Share Unit Plan, outstanding and unvested SBUs and respective dividend equivalents shall be deemed to be vested SBUs and redeemable on the date that is immediately prior to the effective date of the consummation of the transaction resulting from the Change of Control. In the case of Death, Disability or Retirement termination and 15 years or more of service with the Company or its Affiliates, the outstanding and unvested SBU awards and respective dividend equivalents shall be deemed vested and redeemable on the date of the death or on the date on which the grantee's service is terminated due to Disability or Retirement. In the case of Death, Disability or Retirement termination and less than 15 years of service with the Company or its Affiliates, the outstanding and unvested SBU awards and respective dividend equivalents shall be deemed to have vested pro-rata based on the period served from grant date to termination and redeemable on the date of the death or on the date on which the grantee's service is terminated due to Disability or Retirement. In the case of Cause, Involuntary Termination Without Cause and Voluntary Termination outstanding and unvested SBU awards and respective dividend equivalents shall be deemed to be forfeited.

(6) Under the 2017 Omnibus Plan, outstanding and unvested PBU awards and respective dividend equivalents accelerate on a prorated basis under a Change in Control (as defined in the 2017 Omnibus Plan), based on the higher of (A) 100% of the target number of PBUs in the award or (B) the actual payout percentage based on the Committee's assessment of performance of the payment criteria from the beginning of the Payment Criteria Period for the award through the date of the Change of Control (as defined in the 2017 Omnibus Plan). In the case of Death or Disability termination, the outstanding and unvested PBU awards and respective dividend equivalents will remain outstanding and be payable on the payout date of such awards subject to the achievement of the applicable payment criteria. Values shown in the tables above are based on target performance as an estimate of potential payments. In the case of Retirement or Involuntary Termination Without Cause within one year of the award grant date, outstanding and unvested PBU awards and respective dividend equivalents shall be deemed to be forfeited. If Retirement or Involuntary Termination Without Cause occurs one year or more after the grant date, PBU awards and respective dividend equivalents shall be deemed to have vested pro-rata based on the period served from grant date to termination. For Mr. Jipping, pursuant to the Jipping Letter Agreement, upon a voluntary termination of employment, his PBUs, awarded under the 2017 Omnibus Plan, which would otherwise be forfeited, will continue to vest on their normal schedule. The table does not reflect any value for Mr. Jipping's outstanding and unvested PBUs as the payout is subject to achievement of the performance measures. Under the Executive Omnibus Plan, outstanding and unvested PBU awards and respective dividend equivalents shall become redeemable on the Change of Control Redemption Date under a Change in Control (as defined in the Executive Omnibus Plan). In the case of Death, Disability or Retirement termination and 15 years or more of service with the Company or its Affiliates, the outstanding and unvested PBU awards and respective dividend equivalents will remain outstanding and be payable on the payout date of such awards subject to the achievement of the applicable payment criteria. In the case of Death, Disability or Retirement termination and less than 15 years of service with the Company or its Affiliates, the outstanding and unvested PBU awards and respective dividend equivalents shall be deemed to have vested pro-rata based on the period served from grant date to termination and be payable on the payout date of such awards subject to the achievement of the applicable payment criteria. Values shown in the tables above are based on target performance as an estimate of potential payments. In the case of Cause, Involuntary Termination Without Cause and Voluntary Termination outstanding and unvested PBU awards and respective dividend equivalents shall be deemed to be forfeited.

(7) The value of the Postretirement Welfare Plan benefit is included in involuntary termination not for cause and change in control scenarios for Ms. Apsey and Mr. Jipping since their employment agreement includes a provision for deemed satisfaction of the eligibility requirements when terminated under these scenarios. It is assumed each would commence their Postretirement Welfare Benefits at age 58. The rate at which future expected benefit payments were discounted in calculating the Postretirement Welfare Plan present values was 2.94%, the same rate used for fiscal year-end 2020 accounting disclosure of the Postretirement Welfare Plan.

Upon death or disability, a NEO (or his or her estate) receives a pro rata portion of his or her current year target corporate performance bonus. All balances under the cash balance and ESRP shift components of the Qualified Plan, and the ESRP balance (vested portion only for disability), are immediately payable. If the NEO has 10 years of service after age 45, then the NEO (and his or her spouse) is eligible for retiree medical benefits.

Pursuant to his May 2020 Separation and Release Agreement, subject to his compliance with the terms set forth in his employment agreement, Mr. Oginsky will receive (i) a pro rata portion of his 2020 bonus, (ii) continuation of his base salary for (2) years to be paid in accordance with normal Company payroll practices, (iii) continued employee benefits under COBRA with a portion of applicable COBRA premium costs reimbursed for a period of up to 18 months and, (iv) outplacement services for up to (2) years post the termination date. The aforementioned payments and benefits are in exchange for entering into the Separation and Release of Claims Agreement and replaces all employment arrangements and benefits programs available to Mr. Oginsky prior to his termination date. Mr. Oginsky received LTIP payments of $337,849 for SBUs and $743,232 for PBUs that were accelerated and paid in accordance with the LTIP provisions. Mr. Oginsky is entitled to a future payment pursuant to PBU grants made prior to his employment termination, subject to performance conditions and dividend equivalents, in February 2022. Mr. Oginsky will receive a lump sum distribution of his ESRP on March 1, 2021 and at this time he has made no election to commence his Retirement Plan benefit.

Pay Ratio

As required by the U.S. Congress under the Dodd-Frank Wall Street Reform and Consumer Protection Act, and the SEC under Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Linda H. Apsey our CEO:

For 2020, our last completed fiscal year:

the median of the annual total compensation of all employees of the Company (other than Ms. Apsey), was $156,386; and

the annual total compensation of Ms. Apsey as reported in the Summary Compensation Table was $4,451,284.

Based on this information, Ms. Apsey's 2020 annual total compensation was estimated to be 29 times the median annual total compensation for all employees, other than Ms. Apsey.

We determined that, as of December 31, 2020, our employee population consisted of 698 individuals with all of those individuals located in the United States. To identify the "median employee" from our employee population, excluding Ms. Apsey, we utilized a consistently applied compensation measure that included the sum of each employee's 2020 annualized base salary as of December 31, 2020 as reflected in our payroll records, and target 2020 awards made under our annual corporate performance plan, 2017 Omnibus Plan, Executive Omnibus Plan and Fortis Inc. 2020 Restricted Share Unit Plan that were not paid in 2020. We arrayed these values to select our "median employee".

Under Item 402(u), a company is permitted to identify its "median employee" once every three years if there has been no significant change to its employee population or employee compensation arrangements that would result in a significant change to its pay ratio disclosure. We updated our "median employee" for 2020 as it had been three years since we had last identified the "median employee" for this analysis.

Using our "median employee" and Ms. Apsey, we calculated the 2020 Summary Compensation Table values for each according to SEC rules.

Director Compensation

The following table provides information concerning the compensation of each person who served as a non-employee director of the Company during 2020.

Non-Employee Director Compensation Table

Name	Fees Earned or Paid in Cash ($) (1)	Total ($)
(a)	(b)	(h)
Robert A. Elliott	$ 140,000	$ 140,000
Albert Ernst	140,000	140,000
Debora Frodl (2)	46,667	46,667
Alexander I. Greenbaum (3)	—	—
Ronnie Hawkins, Jr. (2)	74,668	74,668
David G. Hutchens (2)	—	—
James P. Laurito	140,000	140,000
Barry V. Perry	140,000	140,000
Sandra E. Pierce (4)	175,417	175,417
Kevin L. Prust	155,000	155,000
A. Douglas Rothwell (4)	148,748	148,748
Thomas G. Stephens (5)	155,000	155,000
Joseph L. Welch (5)	76,505	76,505

(1) Includes annual Board retainer and committee chairmanship retainer, as well as a chairperson fee (for Mr. Welch and Ms. Pierce only).

(2) Ms. Frodl joined the Board in August 2020, Mr. Hawkins joined the Board in June 2020 and Mr. Hutchens joined the Board in January 2021.

(3) Mr. Greenbaum waived all compensation due to him for his service on the Board.

(4) Ms. Pierce was appointed to chairperson of the Board and Mr. Rothwell was appointed Governance and Human Resources chair in May 2020.

(5) Mr. Welch left the Board in May 2020 and Mr. Stephens left the Board in February 2021.

Directors who are employees of the Company do not receive separate compensation for their services as a director. All non-employee directors are compensated under our non-employee director compensation policy, pursuant to which they are paid an annual cash retainer of $140,000. In addition, we pay an additional cash retainer of $15,000 annually to the chair of each Board committee and $50,000 annually to our chairperson. We do not pay per-meeting fees under the policy. Non-employee directors are reimbursed for their out-of-pocket expenses incurred for the performance of their duties as directors.

We maintain a Director Deferred Compensation Plan under which nonqualified deferred compensation is permissible. Only non-employee directors of the Company are eligible to participate in this plan. Directors are allowed to defer up to 100% of their annual board compensation. Investment earnings are based on the various investment options available under the plan and are selected by the individual directors. Distributions will be made when the director ceases to serve on the Board and/or ceases to provide other non-employee consulting services to the Company or any Fortis entity. Messrs. Laurito, Stephens and Ms. Pierce participate in this plan.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.*

The following table sets forth certain information regarding the ownership of our common stock and Fortis' common stock as of February 1, 2021, except as otherwise indicated, by:

- each of our current directors;
- each of the persons named in the "Summary Compensation Table" under Item 11; and

- all current directors and executive officers as a group.

The number of shares beneficially owned is determined under rules of the SEC and the information is not necessarily indicative of beneficial ownership for any other purpose. Under such rules, beneficial ownership includes any shares as to which the individual has sole or shared voting power or investment power and also any shares which the individual has the right to acquire on February 1, 2021 or within 60 days thereafter through the exercise of any stock option or other right. Unless otherwise indicated, each holder has sole investment and voting power with respect to the shares set forth in the following table:

Name of Beneficial Owner	Number of Company Shares Beneficially Owned (#)	Percent of Class (%)	Number of Fortis shares Beneficially Owned (#)		Percent of Class (%)
Linda H. Apsey	—	—	53,889		*
Gretchen L. Holloway	—	—	7,771		*
Jon E. Jipping	—	—	60,000		*
Christine Mason Soneral	—	—	—		—
Krista Tanner	—	—	—		—
Daniel J. Oginsky	—	—	72,621		*
Robert A. Elliott	—	—	—		—
Albert Ernst	—	—	14,511	(1)	*
Debora Frodl	—	—	—		—
Alexander I. Greenbaum	—	—	—		—
Ronnie Hawkins	—	—	—		—
David G. Hutchens	—	—	63,891		—
James P. Laurito	—	—	48,311		*
Sandra E. Pierce	—	—	—		—
Kevin L. Prust	—	—	500		*
A. Douglas Rothwell	—	—	—		—
Thomas G. Stephens	—	—	2,098		*
All current directors and executive officers as a group (17 persons)	—	— %	309,081		*

* Less than one percent

(1) Includes 4,234 shares owned by the spouse of Mr. Ernst.

ITC Investment Holdings, which owns all of our outstanding common stock, is 80.1% owned by FortisUS and 19.9% owned by Eiffel. FortisUS is a wholly-owned subsidiary of Fortis.

At December 31, 2020, there were no securities authorized for issuance under any compensation plans of ITC Holdings.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.*

CERTAIN TRANSACTIONS

Pursuant to its charter, the Governance and Human Resources Committee is charged with monitoring and reviewing issues involving independence and potential conflicts of interest with respect to our directors and executive officers. The Committee also determines whether or not a particular relationship serves the best interest of the Company and its shareholder and whether the relationship should be continued or eliminated. In addition, our Code of Conduct and Ethics generally forbids conflicts of interest unless approved by the Board or a designated committee.

Although the Company does not have a written policy with regard to the approval of transactions between the Company and its executive officers and directors, each director and officer must annually submit a form to the General Counsel disclosing his or her conflicts or potential conflicts of interest or certifying that no such conflicts of interest exist. Throughout the year, if any transaction constituting a conflict of interest arises or circumstances otherwise change that would cause a director's or officer's annual conflict certification to become incorrect, the director or officer must inform the General Counsel of such circumstances. The Committee reviews existing conflicts as well as potential conflicts of interest and determines whether any further action is necessary, such as recommending to the Board whether a director or officer should be requested to offer his or her resignation. Where the Board makes a determination regarding a potential conflict of interest, a majority of the Board (excluding any interested member or members) shall decide upon an appropriate course of action. Additionally, any director or officer who has a question about whether a conflict exists must bring it to the attention of the Company's General Counsel or Chairperson of the Committee.

Clayton Welch, Jennifer Welch, Jessica Uher and Katie Welch (each of whom is a son, daughter or daughter-in-law of Joseph L. Welch, the Company's Chairperson until May 2020) were employed by us as a Senior Engineer, Fleet Manager, Manager of Corporate and Field Facilities, and Senior Accountant, respectively, during 2020 and continue to be employed by us. These individuals are employed on an "at will" basis and compensated on the same basis as our other employees of similar function, seniority and responsibility without regard to their relationship with Mr. Welch. These four individuals, none of whom resides with or is supported financially by Mr. Welch, received aggregate salary, bonus, long-term incentives and taxable perquisites for services rendered in the above capacities totaling $586,777 during 2020.

DIRECTOR INDEPENDENCE

Based on the absence of any material relationship between them and us, other than their capacities as directors, the Board has determined that Mmes. Frodl and Pierce and Messrs. Elliott, Ernst, Hawkins, Jr., Prust, and Rothwell are "independent" as defined in the Shareholders Agreement. In addition, our Board has determined that, as the committees are currently constituted, a majority of the members of the Audit and Risk Committee are "independent" as defined in the Shareholders Agreement. None of the directors determined to be independent is or ever has been employed by us.

An independent director under the Shareholders Agreement is a director who meets all of the following requirements: (a) is elected by the shareholders of ITC Investment Holdings; (b) is designated as an independent director by the ITC Investment Holdings' board and Company Board, or the shareholders of ITC Investment Holdings; (c) is not a director that is nominated by Finn Investment Pte Ltd or any successor or permitted assign thereof and appointed as a member of the ITC Investment Holdings' board and Company Board in accordance with the Shareholders Agreement; (d) is not and during the three years prior to being designated as an independent director has not been any of the following: (i) a director of FortisUS or any of its affiliates (other than ITC Investment Holdings or the Company); or (ii) an officer or employee of ITC Investment Holdings, the Company, FortisUS or any of their affiliates; and (e) would meet the definition of "independent director" under the NYSE Listed Company Manual if such director were a member of the board of directors of Fortis, FortisUS, ITC Investment Holdings, or the Company (assuming, in the case of FortisUS, ITC Investment Holdings and the Company, that such entities were listed on the NYSE).

Mr. Elliott serves on the board of directors of UNS Energy Corporation, a wholly-owned subsidiary of FortisUS. When determining Mr. Elliott's independence, the board and shareholders agreed to waive the requirements set forth in the definition of independent director under the Shareholders Agreement which states that a director is not and during the three years prior to being designated as a director of the company has not served as a director of FortisUS or any of its affiliates.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES.*

The following table provides a summary of the aggregate fees incurred for Deloitte's services in 2020 and 2019:

	2020	2019
Audit fees (1)	$ 1,995,000	$ 1,901,000
Audit-related fees (2)	56,000	54,000
Tax fees (3)	16,000	208,000
All other fees (4)	4,000	9,000
Total fees	$ 2,071,000	$ 2,172,000

(1) Audit fees were for professional services rendered for the audit of our consolidated financial statements and internal controls and reviews of the interim consolidated financial statements included in quarterly reports and services that are normally provided by Deloitte in connection with statutory and regulatory filing engagements.

(2) Audit-related fees were for assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements and are not reported under "Audit Fees." These services include audit of our employee benefit plans.

(3) Tax fees were professional services for federal and state tax compliance, tax advice and tax planning.

(4) All other fees were for services other than the services reported above. These services included subscriptions to the Deloitte Accounting Research Tool and attendance at Deloitte sponsored conferences and labs.

The Audit and Risk Committee of the Board of Directors does not consider the provision of the services described above by Deloitte to be incompatible with the maintenance of Deloitte's independence.

The Audit and Risk Committee has adopted a pre-approval policy for all audit and non-audit services pursuant to which it pre-approves all audit and non-audit services provided by the independent registered public accounting firm prior to the engagement with respect to such services. To the extent that we need an engagement for audit and/or non-audit services between Audit and Risk Committee meetings, the Audit and Risk Committee chairman is authorized by the Audit and Risk Committee to approve the required engagement on its behalf.

The Audit and Risk Committee approved all of the services performed by Deloitte in 2020 pursuant to the pre-approval policy.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.*

(a) (1) Financial Statements:

Management's Report on Internal Control over Financial Reporting

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Financial Position as of December 31, 2020 and 2019

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2020, 2019 and 2018

Consolidated Statements of Changes in Stockholder's Equity for the Years Ended December 31, 2020, 2019 and 2018

Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019 and 2018

Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Schedule I — Condensed Financial Information of Registrant

All other schedules for which provision is made in Regulation S-X either (i) are not required under the related instructions or are inapplicable and, therefore, have been omitted, or (ii) the information required is included in the consolidated financial statements or the notes thereto that are a part hereof.

(b) Exhibit Listing

The following exhibits are filed as part of this report or filed previously and incorporated by reference to the filing indicated. Our SEC file number is 001-32576.

Exhibit No.	**Description of Exhibit**
2.1	Agreement and Plan of Merger, dated as of February 9, 2016, among FortisUS Inc., Element Acquisition Sub Inc., Fortis Inc., and ITC Holdings Corp. (filed with Registrant's Form 8-K on February 11, 2016)
3.1	Restated Articles of Incorporation of ITC Holdings Corp. (filed with Registrant's Form 10-Q for the quarter ended September 30, 2016)
3.2	Eighth Amended and Restated Bylaws of ITC Holdings Corp.
4.3	Indenture, dated as of July 16, 2003, between ITC Holdings Corp. and BNY Midwest Trust Company, as trustee (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
4.5	First Mortgage and Deed of Trust, dated as of July 15, 2003, between International Transmission Company and BNY Midwest Trust Company, as trustee (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
4.6	First Supplemental Indenture, dated as of July 15, 2003, supplementing the First Mortgage and Deed of Trust dated as of July 15, 2003, between International Transmission Company and BNY Midwest Trust Company, as trustee (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
4.7	Second Supplemental Indenture, dated as of July 15, 2003, supplementing the First Mortgage and Deed of Trust dated as of July 15, 2003, between International Transmission Company and BNY Midwest Trust Company, as trustee (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
4.8	Amendment to Second Supplemental Indenture, dated as of January 19, 2005, between International Transmission Company and BNY Midwest Trust Company, as trustee (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
4.9	Second Amendment to Second Supplemental Indenture, dated as of March 24, 2006, between International Transmission Company and The Bank of New York Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on March 30, 2006)
4.10	Third Supplemental Indenture, dated as of March 28, 2006, supplementing the First Mortgage and Deed of Trust dated as of July 15, 2003, between International Transmission Company and BNY Midwest Trust Company, as trustee (filed with Registrant's Form 8-K on March 30, 2006)

Exhibit No.	Description of Exhibit
4.12	Second Supplemental Indenture, dated as of October 10, 2006, supplemental to the Indenture dated as of July 16, 2003, between the Registrant and The Bank of New York Trust Company, N.A., (as successor to BNY Midwest Trust Company, as trustee) (filed with Registrant's Form 8-K on October 10, 2006)
4.14	First Mortgage Indenture between Michigan Electric Transmission Company, LLC and JPMorgan Chase Bank, dated as of December 10, 2003 (filed with Registrant's Form 10-Q for the quarter ended September 30, 2006)
4.17	ITC Holdings Corp. Note Purchase Agreement, dated as of September 20, 2007 (filed with Registrant's Form 10-Q for the quarter ended September 30, 2007)
4.18	Third Supplemental Indenture, dated as of January 24, 2008, supplemental to the Indenture dated as of July 16, 2003, between the Registrant and The Bank of New York Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on January 25, 2008)
4.19	First Mortgage and Deed of Trust, dated as of January 14, 2008, between ITC Midwest LLC and The Bank of New York Trust Company, N.A., as trustee (filed with Registrant's Form 8-K on February 1, 2008)
4.20	First Supplemental Indenture, dated as of January 14, 2008, supplemental to the First Mortgage Indenture between ITC Midwest LLC and The Bank of New York Trust Company, N.A., as trustee, First Mortgage and Deed of Trust, dated as of January 14, 2008 (filed with Registrant's Form 8-K on February 1, 2008)
4.23	Second Supplemental Indenture, dated as of December 15, 2008, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee, to the First Mortgage and Deed of Trust, dated as of January 14, 2008 (filed with Registrant's Form 8-K on December 23, 2008)
4.24	Third Supplemental Indenture, dated as of November 25, 2008, between METC and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank, N.A.), as trustee, to the First Mortgage Indenture between Michigan Electric Transmission Company, LLC and JPMorgan Chase Bank, dated as of December 10, 2003 (filed with Registrant's Form 8-K on December 23, 2008)
4.25	Fourth Supplemental Indenture, dated as of December 11, 2009, between ITC Holdings Corp. and The Bank of New York Mellon Trust Company, N.A. (f.k.a. The Bank of New York Trust Company, N.A., as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on December 14, 2009)
4.26	Fourth Supplemental Indenture, dated as of December 10, 2009, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 8-K on December 17, 2009)
4.27	Fifth Supplemental Indenture, dated as of April 20, 2010, between Michigan Electric Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank), as trustee (filed with Registrant's Form 8-K on May 10, 2010)
4.28	Third Supplemental Indenture, dated as of December 15, 2008, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 10-Q for the quarter ended June 30, 2011)
4.29	Fifth Supplemental Indenture, dated as of July 15, 2011, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 10-Q for the quarter ended June 30, 2011)
4.30	Sixth Supplemental Indenture, dated as of November 29, 2011, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 8-K on December 1, 2011)
4.31	Sixth Supplemental Indenture, dated as of October 5, 2012, between Michigan Electric Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank), as trustee (filed with Registrant's Form 8-K on October 29, 2012)
4.32	Seventh Supplemental Indenture, dated as of March 18, 2013, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 8-K on April 8, 2013)
4.33	Indenture, dated as of April 18, 2013, between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee (including form of note) (filed with Registrant's Form S-3 on April 18, 2013)
4.34	First Supplemental Indenture, dated as of July 3, 2013, between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee (including forms of notes) (filed with Registrant's Form 8-K on July 3, 2013)

Exhibit No.	Description of Exhibit
4.35	Fifth Supplemental Indenture, dated as of August 7, 2013, between International Transmission Company and The Bank of New York Mellon Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (including form of bonds) (filed with Registrant's Form 8-K on August 16, 2013)
4.36	Fifth Supplemental Indenture, dated May 16, 2014, between ITC Holdings Corp. and The Bank of New York Mellon Trust Company, N.A. (f.k.a. The Bank of New York Trust Company, N.A., as successor to BNY Midwest Trust Company), as Trustee (filed with Registrant's Form 8-K on May 16, 2014)
4.38	Second Supplemental Indenture, dated as of June 4, 2014 between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee, together with form of 3.65% Senior Note due 2024 (filed with Registrant's Form 8-K on June 4, 2014)
4.39	Sixth Supplemental Indenture, dated as of May 23, 2014, between International Transmission Company and The Bank of New York Mellon Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on June 10, 2014)
4.40	First Mortgage and Deed of Trust, dated as of November 12, 2014, between ITC Great Plains, LLC and Wells Fargo Bank, National Association, as trustee (filed with Registrant's Form 8-K on November 26, 2014)
4.41	First Supplemental Indenture, dated as of November 12, 2014, between ITC Great Plains, LLC and Wells Fargo Bank, National Association, as trustee (filed with Registrant's Form 8-K on November 26, 2014)
4.42	Seventh Supplemental Indenture, dated as of December 5, 2014, between Michigan Electric Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank), as trustee (filed with Registrant's Form 8-K on December 22, 2014)
4.43	Eighth Supplemental Indenture, dated as of March 18, 2015, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 8-K on April 8, 2015)
4.44	Eighth Supplemental Indenture, dated as of March 31, 2016, between Michigan Electric Transmission Company, LLC and Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank), as trustee (filed with Registrant's Form 8-K on April 26, 2016)
4.45	Third Supplemental Indenture, dated as of July 5, 2016, between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee, together with form of 3.25% Note due 2026 (filed with Registrant's Form 8-K on July 5, 2016)
4.46	Ninth Supplemental Indenture, dated as of March 15, 2017, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.), as trustee (filed with Registrant's Form 8-K on April 18, 2017)
4.47	Fourth Supplemental Indenture, dated as of November 14, 2017 between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee (with Form of 2.700% Notes due 2022 and Form of 3.350% Notes due 2027) (filed with Registrant's Form 8-K on November 15, 2017)
4.48	Seventh Supplemental Indenture, dated as of March 14, 2018, between International Transmission Company and The Bank of New York Mellon Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on March 29, 2018)
4.49	Tenth Supplemental Indenture, dated as of September 28, 2018, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.) as trustee (filed with Registrant's Form 8-K on November 2, 2018)
4.50	Ninth Supplemental Indenture, dated as of November 28, 2018, between Michigan Electric Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to JP Morgan Chase Bank), as trustee (filed with Registrant's Form 8-K on January 15, 2019)
4.51	Eighth Supplemental Indenture, dated as of August 14, 2019, between International Transmission Company and The Bank of New York Mellon Trust Company, N.A. (as successor to BNY Midwest Trust Company), as trustee (filed with Registrant's Form 8-K on August 28, 2019).
4.52	Fifth Supplemental Indenture, dated as of May 14, 2020, between ITC Holdings Corp. and Wells Fargo Bank, National Association, as trustee (with Form of 2.95% Notes due 2030) (filed with Registrant's Form 8-K on May 14, 2020).
4.53	Eleventh Supplemental Indenture, dated as of May 8, 2020, between ITC Midwest LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Trust Company, N.A.) as trustee (filed with Registrant's Form 8-K on July 15, 2020).

Exhibit No.	Description of Exhibit
4.54	Tenth Supplemental Indenture, dated as of August 12, 2020, between Michigan Electric Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to JP Morgan Chase Bank), as trustee (filed with Registrant's Form 8-K on October 14, 2020).
*10.27	Deferred Compensation Plan (filed with Registrant's Registration Statement on Form S-1, as amended, Reg. No. 333-123657)
10.51	Form of Amended and Restated Easement Agreement between Consumers Energy Company and Michigan Electric Transmission Company (filed with Registrant's Form 10-Q for the quarter ended September 30, 2006)
*10.81	Executive Supplemental Retirement Plan (filed with Registrant's 2008 Form 10-K)
*10.109	Employment Agreement between ITC Holdings Corp. and Linda H. Blair, effective as of December 21, 2012 (filed with Registrant's Form 8-K on December 26, 2012)
*10.110	Employment Agreement between ITC Holdings Corp. and Jon E. Jipping, effective as of December 21, 2012 (filed with Registrant's Form 8-K on December 26, 2012)
*10.111	Employment Agreement between ITC Holdings Corp. and Daniel J. Oginsky, effective as of December 21, 2012 (filed with Registrant's Form 8-K on December 26, 2012)
*10.120	First Amendment to Executive Supplemental Retirement Plan, dated as of May 16, 2013 (filed with Registrant's Form 10-Q for the quarter ended June 30, 2013)
*10.122	Recoupment Policy and Related Consent, effective January 1, 2014 (filed with Registrant's Form 8-K on December 2, 2013)
*10.150	Employment Agreement between ITC Holdings Corp. and Christine Mason Soneral, effective as of February 3, 2015 (filed with Registrant's Form 10-Q for the quarter ended June 30, 2015)
*10.168	Letter Agreement, dated as of October 14, 2016, between ITC Holdings Corp. and Linda H. Blair (filed with Registrant's Form 8-K on October 12, 2016)
*10.172	Employment Agreement between ITC Holdings Corp. and Gretchen L. Holloway, effective as of July 10, 2017
*10.173	Letter Agreement, dated as of October 12, 2016 between ITC Holdings Corp. and Christine Mason Soneral (filed with Registrant's 2016 Form 10-K)
*10.176	2017 Omnibus Plan, effective February 27, 2017 (filed with Registrant's Form 10-Q for the quarter ended March 31, 2017)
*10.177	Summary of 2017 Annual Incentive Plan (filed with Registrant's Form 10-Q for the quarter ended March 31, 2017)
*10.178	Form of Service-Based Unit Award Agreement under 2017 Omnibus Plan (February 2017) (filed with Registrant's Form 10-Q for the quarter ended March 31, 2017)
*10.179	Form of Performance-Based Unit Award Agreement under 2017 Omnibus Plan (February 2017) (filed with Registrant's Form 10-Q for the quarter ended March 31, 2017)
10.182	Amendment to 2017 Omnibus Plan, dated as of July 10, 2017 (filed with Registrant's Form 10-Q for the quarter ended June 30, 2017)
10.183	ITC Holdings Corp. Director Deferred Compensation Plan, effective March 1, 2017 (filed with Registrant's Form 10-Q for the quarter ended June 30, 2017)
10.184	ITC Holdings Revolving Credit Agreement, dated as of October 23, 2017, among ITC Holdings Corp., with the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, JPMorgan Chase Bank, N.A., as administrative agent for the Lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with Registrant's Form 8-K on October 23, 2017)

Exhibit No.	Description of Exhibit
10.185	ITCTransmission Revolving Credit Agreement, dated as of October 23, 2017, among International Transmission Company, with the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, JPMorgan Chase Bank, N.A., as administrative agent for the Lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with Registrant's Form 8-K on October 23, 2017)
10.186	METC Revolving Credit Agreement, dated as of October 23, 2017, among Michigan Electric Transmission Company, LLC, with the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, JPMorgan Chase Bank, N.A., as administrative agent for the Lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with Registrant's Form 8-K on October 23, 2017)
10.187	ITC Midwest Revolving Credit Agreement, dated as of October 23, 2017, among ITC Midwest LLC, with the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, JPMorgan Chase Bank, N.A., as administrative agent for the Lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with Registrant's Form 8-K on October 23, 2017)
10.188	ITC Great Plains Revolving Credit Agreement, dated as of October 23, 2017, among ITC Great Plains, LLC, with the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, JPMorgan Chase Bank, N.A., as administrative agent for the Lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with Registrant's Form 8-K on October 23, 2017)
*10.190	International Transmission Company Executive Deferred Compensation Plan, effective January 1, 2019 (filed with Registrant's 2018 Form 10-K)
*10.191	ITC Holdings Corp. Director Deferred Compensation Plan, effective January 1, 2019 (filed with Registrant's 2018 Form 10-K)
*10.192	Letter Agreement, effective as of February 18, 2019, between ITC Holdings Corp. and Jon E. Jipping (filed with Registrant's Form 8-K on February 22, 2019).
10.193	Term Loan Credit Agreement, dated as of June 12, 2019, among ITC Holdings Corp., the various financial institutions and other persons from time to time parties thereto as lenders and Toronto-Dominion (Texas) LLC, as administrative agent for the Lenders, Mizuho Bank, Ltd. and TD Securities (USA) LLC, as joint lead arrangers and joint bookrunners and Mizuho Bank, Ltd., as syndication agent (filed with the Registrant's Form 8-K on June 14, 2019).
10.194	ITC Holdings Amendment and Restatement Agreement dated as of January 10, 2020, among ITC Holdings Corp., the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, Wells Fargo Bank, National Association, in its capacity as successor administrative agent and JPMorgan Chase Bank, N.A., in its capacity as resigning administrative agent, amending and restating as of January 10, 2020 in the form attached as Exhibit A thereto the Revolving Credit Agreement, dated as of October 23, 2017, among ITC Holdings Corp., the banks, financial institutions and other institutional party thereto, JPMorgan Chase Bank, N.A., as administrative agent for the lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with the Registrant's Form 8-K on January 10, 2020).

Exhibit No.	Description of Exhibit
10.195	ITCTransmission Amendment and Restatement Agreement dated as of January 10, 2020, among International Transmission Company, the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, Wells Fargo Bank, National Association, in its capacity as successor administrative agent and JPMorgan Chase Bank, N.A., in its capacity as resigning administrative agent, amending and restating as of January 10, 2020 in the form attached as Exhibit A thereto the Revolving Credit Agreement, dated as of October 23, 2017, among International Transmission Company, the banks, financial institutions and other institutional party thereto, JPMorgan Chase Bank, N.A., as administrative agent for the lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with the Registrant's Form 8-K on January 10, 2020).
10.196	METC Amendment and Restatement Agreement dated as of January 10, 2020, among Michigan Electric Transmission Company, LLC, the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, Wells Fargo Bank, National Association, in its capacity as successor administrative agent and JPMorgan Chase Bank, N.A., in its capacity as resigning administrative agent, amending and restating as of January 10, 2020 in the form attached as Exhibit A thereto the Revolving Credit Agreement, dated as of October 23, 2017, among Michigan Electric Transmission Company, LLC, the banks, financial institutions and other institutional party thereto, JPMorgan Chase Bank, N.A., as administrative agent for the lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with the Registrant's Form 8-K on January 10, 2020).
10.197	ITC Midwest Amendment and Restatement Agreement dated as of January 10, 2020, among ITC Midwest LLC, the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, Wells Fargo Bank, National Association, in its capacity as successor administrative agent and JPMorgan Chase Bank, N.A., in its capacity as resigning administrative agent, amending and restating as of January 10, 2020 in the form attached as Exhibit A thereto the Revolving Credit Agreement, dated as of October 23, 2017, among ITC Midwest LLC, the banks, financial institutions and other institutional party thereto, JPMorgan Chase Bank, N.A., as administrative agent for the lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with the Registrant's Form 8-K on January 10, 2020).
10.198	ITC Great Plains Amendment and Restatement Agreement dated as of January 10, 2020, among ITC Great Plains, LLC, the banks, financial institutions and other institutional lenders listed on the respective signature pages thereof, Wells Fargo Bank, National Association, in its capacity as successor administrative agent and JPMorgan Chase Bank, N.A., in its capacity as resigning administrative agent, amending and restating as of January 10, 2020 in the form attached as Exhibit A thereto the Revolving Credit Agreement, dated as of October 23, 2017, among ITC Great Plains, LLC, the banks, financial institutions and other institutional party thereto, JPMorgan Chase Bank, N.A., as administrative agent for the lenders, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Wells Fargo Securities, LLC, The Bank of Nova Scotia and Mizuho Bank, Ltd., as joint lead arrangers and joint bookrunners, Barclays Bank PLC and Wells Fargo Bank, National Association, as co-syndication agents and The Bank of Nova Scotia and Mizuho Bank, Ltd. as co-documentation agents (filed with the Registrant's Form 8-K on January 10, 2020).
10.199	Term Loan Credit Agreement, dated as of January 23, 2020, among Michigan Electric Transmission Company, LLC, the various financial institutions and other persons from time to time parties thereto as lenders and Toronto Dominion (Texas) LLC, as administrative agent for the lenders and TD Securities (USA) LLC, as sole lead arranger and bookrunner (filed with the Registrant's Form 8-K on January 23, 2020).
*10.200	2017 Omnibus Plan, as amended July 10, 2017 and February 4, 2020 (filed with Registrant's 2019 Form 10-K).
*10.201	Executive Omnibus Plan, effective January 2020. (filed with Registrant's 2019 Form 10-K)
*10.202	Form of Performance-Based Unit Award Agreement under Executive Omnibus Plan (January 2020). (Filed with Registrant's 2019 Form 10-K)
*10.203	Employment Agreement between ITC Holdings Corp. and Krista K. Tanner, effective as of February 18, 2019.
*10.204	Fortis Inc. 2020 Restricted Share Unit Plan, effective January 1, 2020 (filed with Registrant's Form 10-Q for the quarter ended March 31, 2020).
*10.205	Form of Restricted Share Unit Grant Agreement under Fortis Inc. 2020 Restricted Share Unit Plan (January, 2020) (filed with Registrant's Form 10-Q for the quarter ended March 31, 2020).

Exhibit No.	Description of Exhibit
*10.206	Separation and Release Agreement, effective as of May 18, 2020, between ITC Holdings Corp. and Daniel J. Oginsky.
21	List of Subsidiaries
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data file because its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Taxonomy Extension Schema
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF	Inline XBRL Taxonomy Extension Definition Database
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in Inline XBRL

* Management contract or compensatory plan or arrangement.

SCHEDULE I — Condensed Financial Information of Registrant

ITC HOLDINGS CORP.

CONDENSED STATEMENTS OF FINANCIAL POSITION (PARENT COMPANY ONLY)

(In millions of USD, except share data)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 2	$ 2
Accounts receivable from subsidiaries	9	17
Intercompany tax receivable from subsidiaries	8	3
Prepaid and other current assets	—	5
Total current assets	19	27
Other assets		
Investment in subsidiaries	5,496	5,136
Deferred income taxes	160	140
Advances to subsidiaries	54	5
Other assets	101	94
Total other assets	5,811	5,375
TOTAL ASSETS	$ 5,830	$ 5,402
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accrued compensation	$ 55	$ 61
Accrued interest	23	21
Debt maturing within one year	67	200
Other current liabilities	8	11
Total current liabilities	153	293
Accrued pension and postretirement liabilities	59	73
Other liabilities	58	37
Long-term debt (net of deferred financing fees and discount of $21 and $17, respectively)	3,266	2,767
TOTAL LIABILITIES	3,536	3,170
STOCKHOLDER'S EQUITY		
Common stock, without par value, 235,000,000 shares authorized, 224,203,112 shares issued and outstanding at December 31, 2020 and 2019	892	892
Retained earnings	1,410	1,333
Accumulated other comprehensive (loss) income	(8)	7
Total stockholder's equity	2,294	2,232
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 5,830	$ 5,402

See notes to condensed financial statements (parent company only).

SCHEDULE I — Condensed Financial Information of Registrant

ITC HOLDINGS CORP.

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (PARENT COMPANY ONLY)

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
Other income (expense), net	$ 5	$ 5	$ 1
General and administrative expense	(20)	(25)	(7)
Taxes other than income taxes	(1)	(2)	—
Interest expense	(122)	(119)	(114)
LOSS BEFORE INCOME TAXES	(138)	(141)	(120)
INCOME TAX BENEFIT	(43)	(44)	(30)
LOSS AFTER TAXES	(95)	(97)	(90)
EQUITY IN SUBSIDIARIES' NET EARNINGS	502	525	420
NET INCOME	407	428	330
OTHER COMPREHENSIVE (LOSS) INCOME			
Derivative instruments (net of tax of $7 for the year ended December 31, 2020, $1 for the year ended December 31, 2019 and less than $1 for the year ended December 31, 2018)	(15)	3	1
TOTAL OTHER COMPREHENSIVE (LOSS) INCOME, NET OF TAX	(15)	3	1
TOTAL COMPREHENSIVE INCOME	$ 392	$ 431	$ 331

See notes to condensed financial statements (parent company only).

SCHEDULE I — Condensed Financial Information of Registrant
ITC HOLDINGS CORP.
CONDENSED STATEMENTS OF CASH FLOWS (PARENT COMPANY ONLY)

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 407	$ 428	$ 330
Adjustments to reconcile net income to net cash used in operating activities:			
Equity in subsidiaries' earnings	(502)	(525)	(420)
Dividends from subsidiaries	3	3	26
Deferred and other income taxes	(46)	(51)	(23)
Net intercompany tax payments from (to) subsidiaries	33	14	59
Other	2	6	2
Changes in assets and liabilities, exclusive of changes shown separately:			
Accounts receivable from subsidiaries	9	9	(4)
Intercompany tax receivable from subsidiaries	(4)	11	(13)
Income tax receivable	—	1	14
Accrued compensation	(6)	31	2
Other current and non-current assets and liabilities, net	6	9	13
Net cash used in operating activities	(98)	(64)	(14)
CASH FLOWS FROM INVESTING ACTIVITIES			
Equity contributions to subsidiaries	(88)	(120)	(202)
Return of capital from subsidiaries	228	239	324
Advances to subsidiaries	(50)	—	—
Other	(2)	(1)	(1)
Net cash provided by investing activities	88	118	121
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	700	—	—
Borrowings under revolving credit agreement	293	72	37
Borrowings under term loan credit agreements	200	200	—
Net issuance of commercial paper	(133)	200	—
Retirement of long-term debt — including extinguishment of debt costs	—	(203)	—
Repayments of revolving credit agreement	(290)	(75)	—
Repayments of term loan credit agreement	(400)	—	—
Dividends to ITC Investment Holdings	(330)	(250)	(200)
Settlement of interest rate swaps	(23)	—	—
Other	(7)	—	(1)
Net cash provided by (used in) financing activities	10	(56)	(164)
NET INCREASE (DECREASE) IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	—	(2)	(57)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — Beginning of period	2	4	61
CASH, CASH EQUIVALENTS AND RESTRICTED CASH — End of period	$ 2	$ 2	$ 4

See notes to condensed financial statements (parent company only).

SCHEDULE I — Condensed Financial Information of Registrant

ITC HOLDINGS CORP.

NOTES TO CONDENSED FINANCIAL STATEMENTS (PARENT COMPANY ONLY)

1. GENERAL

For ITC Holdings Corp.'s ("ITC Holdings," "we," "our" and "us") presentation (Parent Company only), the investment in subsidiaries is accounted for using the equity method. The condensed parent company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of ITC Holdings appearing in this Annual Report on Form 10-K.

As a holding company with no business operations, ITC Holdings' assets consist primarily of investments in our subsidiaries. ITC Holdings' material cash inflows are only from dividends and other payments received from our subsidiaries, the proceeds raised from the sale of debt securities, issuances under our commercial paper program and borrowings under our revolving and term loan term credit agreements. ITC Holdings may not be able to access cash generated by our subsidiaries in order to fulfill cash commitments. The ability of our subsidiaries to make dividend and other payments to us is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the FPA and applicable state laws. In addition, there are practical limitations on using the net assets of each of our Regulated Operating Subsidiaries as of December 31, 2020 for dividends based on management's intent to maintain the FERC-approved capital structure targeting 60% equity and 40% debt for each of our Regulated Operating Subsidiaries. These net assets are included in Schedule I as the line-item "Investments in subsidiaries." Each of our subsidiaries, however, is legally distinct from us and has no obligation, contingent or otherwise, to make funds available to us.

Recent Developments Regarding the COVID-19 Pandemic

In March 2020, the World Health Organization declared COVID-19 a pandemic. Efforts to control the recent outbreak of COVID-19 have resulted in impacts to businesses and facilities in various industries around the world, such as operating restrictions and closures, and disruptions to the global economy and supply chains. To date, COVID-19 has not had a material impact on our results of operations, cash flows or financial condition.

The duration and total impact on our operations from COVID-19 is unknown at this time and will ultimately depend on the duration and severity of the pandemic, the length that the various business restrictions are in effect, the impact of recent resurgences of COVID-19 cases and deaths in the United States, and the efficacy and distribution of COVID-19 vaccines. We are continuing to monitor developments and cannot predict whether COVID-19 will have a material impact on our results of operations, cash flows or financial condition. We are also monitoring the evolving situation and guidance from federal, state and local public health authorities. We are taking steps to mitigate the potential risks to us and our employees posed by COVID-19, including enabling remote work arrangements for employees when appropriate, and are following all government requirements to reduce the transmission of COVID-19.

2. DEBT

As of December 31, 2020, the maturities of our debt outstanding were as follows:

(In millions of USD)	
2021	$ 67
2022	500
2023	287
2024	400
2025	—
2026 and thereafter	2,100
Total	$ 3,354

Refer to Note 10 to the consolidated financial statements for additional information on the ITC Holdings Senior Notes, the ITC Holdings Revolving and Term Loan Credit Agreements, the ITC Holdings Commercial Paper Program and the ITC Holdings Derivative Instruments and Hedging Activities.

Fixed Rate Debt

Based on the borrowing rates obtained from third party lending institutions currently available for bank loans with similar terms and average maturities from active markets, the fair value of the ITC Holdings Senior Notes was $3,670 million and $2,752 million at December 31, 2020 and 2019, respectively. The total book value of the ITC Holdings Senior Notes, net of discount and deferred financing fees, was $3,229 million and $2,533 million at December 31, 2020 and 2019, respectively. The fair values of the ITC Holdings Senior Notes represent Level 2 under the three-tier hierarchy described in Note 13 to the consolidated financial statements.

Revolving and Term Loan Credit Agreements

At December 31, 2020 and 2019, we had $37 million and $234 million respectively, outstanding under our revolving and term loan credit agreements, which are variable rate loans. The fair value of these loans approximates book value based on the borrowing rates currently available for variable rate loans obtained from third party lending institutions. The fair values of the revolving and term loan credit agreements represent Level 2 under the three-tier hierarchy described in Note 13 to the consolidated financial statements

Other Financial Instruments

The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents, special deposits and commercial paper, approximates their fair value due to the short-term nature of these instruments.

3. RELATED-PARTY TRANSACTIONS

Our related-party transactions during were as follows:

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
Equity contributions to subsidiaries	$ (88)	$ (120)	$ (202)
Dividends from subsidiaries (a)	3	3	26
Return of capital from subsidiaries (a)	228	239	324
Net income tax payments (to) from: (b)			
ITCTransmission	$ 17	$ 7	$ 39
METC	9	4	7
ITC Midwest	1	3	3
ITC Great Plains	6	(1)	9
ITC Interconnection	—	1	1

(a) Includes ITCTransmission, MTH, ITC Midwest and other subsidiaries.

(b) The net income tax payments were pursuant to intercompany tax sharing arrangements, and the total of these tax payments is presented as a net cash outflow or inflow from operating activities in the condensed parent company statements of cash flows. Other reconciling items between the parent company and the consolidated tax liabilities are presented as deferred and other income taxes in the adjustments to reconcile net income to net cash provided by operating activities. Additionally, ITC Holdings paid its subsidiaries for NOLs utilized by the consolidated group.

Net Intercompany Receivables and Payables

We may incur charges from our subsidiaries for general corporate expenses incurred. In addition, we may perform additional services for, or receive additional services from our subsidiaries. These transactions are in the normal course of business and payments for these services are settled through accounts receivable and accounts payable, as necessary. We generally settle our intercompany balances with our affiliates on a net basis monthly.

Intercompany Tax Sharing Arrangement

As discussed in Note 1 to the condensed financial statements of the parent company, we are a holding company with no business operations. We file consolidated income tax returns that include our affiliates, which are taxed as a corporation for federal and Michigan income tax purposes. We operate under an intercompany tax sharing arrangement with our subsidiaries and as a result may receive or pay federal and state income tax based on their stand-alone company tax positions.

Retirement Benefits

We are the plan sponsor for a pension plan, other postretirement plans and a defined contribution plan. The benefits-related expenses recorded by our affiliates result from the inclusion of benefit costs as a component of the total charge for services performed by our employees under the cost assignment and allocation methods used by us and our subsidiaries.

Intercompany Loan Agreement

On September 21, 2020, we advanced an intercompany loan to ITC Transmission totaling $50 million, which remained outstanding at December 31, 2020. We received interest payments of less than $1 million during the year ended December 31, 2020 from ITC Transmission associated with this intercompany loan. Additionally, at December 31, 2020 we had a $4 million intercompany loan with ITC Interconnection. During the year ended December 31, 2020, we received principal and interest payments of less than $1 million from ITC Interconnection associated with this intercompany loan.

4. SUPPLEMENTAL FINANCIAL INFORMATION

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported on the condensed statements of financial position that sum to the total of the same such amounts shown in the condensed statements of cash flows:

	December 31,			
(In millions of USD)	**2020**	**2019**	**2018**	**2017**
Cash and cash equivalents	$ 2	$ 2	$ 3	$ 60
Restricted cash included in:				
Other non-current assets	—	—	1	1
Total cash, cash equivalents and restricted cash	$ 2	$ 2	$ 4	$ 61

Supplementary Cash Flows Information

	Year Ended December 31,		
(In millions of USD)	**2020**	**2019**	**2018**
Supplementary cash flows information:			
Interest paid	$ 116	$ 117	$ 117
Income taxes paid	2	—	—
Income tax refunds received	2	3	13

ITEM 16. *FORM 10-K SUMMARY.*

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Novi, State of Michigan, on February 11, 2021.

ITC HOLDINGS CORP.

By: /s/ LINDA H. APSEY
Linda H. Apsey
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ LINDA H. APSEY Linda H. Apsey	President and Chief Executive Officer (principal executive officer)	February 11, 2021
/s/ GRETCHEN L. HOLLOWAY Gretchen L. Holloway	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 11, 2021
/s/ SANDRA E. PIERCE Sandra E. Pierce	Director and Chairman	February 11, 2021
/s/ ROBERT A. ELLIOTT Robert A. Elliott	Director	February 11, 2021
/s/ ALBERT ERNST Albert Ernst	Director	February 11, 2021
/s/ DEBORA FRODL Debora Frodl	Director	February 11, 2021
/s/ ALEXANDER I. GREENBAUM Alexander I. Greenbaum	Director	February 11, 2021
/s/ RONNIE D. HAWKINS, JR Ronnie D. Hawkins, Jr	Director	February 11, 2021
/s/ DAVID G. HUTCHENS David G. Hutchens	Director	February 11, 2021
/s/ JAMES P. LAURITO James P. Laurito	Director	February 11, 2021
/s/ KEVIN L. PRUST Kevin L. Prust	Director	February 11, 2021
/s/ A. DOUGLAS ROTHWELL A. Douglas Rothwell	Director	February 11, 2021