

Consolidated Financial Statements

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2021 and 2020

Consolidated Financial Statements

Table of Contents

Management's Report on Internal Control over Financial Reporting	2	NOTE 9	Other Assets	24
Report of Independent Registered Public Accounting Firm		NOTE 10	Property, Plant and Equipment	24
("PCAOB ID No. 01208") - Opinion on the Financial Statements	3	NOTE 11	Intangible Assets	26
Report of Independent Registered Public Accounting Firm - Opinion on		NOTE 12	Goodwill	26
Internal Control over Financial Reporting	5	NOTE 13	Accounts Payable and Other Current Liabilities	26
Consolidated Balance Sheets	6	NOTE 14	Long-Term Debt	27
Consolidated Statements of Earnings	7	NOTE 15	Leases	30
Consolidated Statements of Comprehensive Income	7	NOTE 16	Other Liabilities	31
Consolidated Statements of Cash Flows	8	NOTE 17	Earnings Per Common Share	32
Consolidated Statements of Changes in Equity	9	NOTE 18	Preference Shares	32
Notes to Consolidated Financial Statements		NOTE 19	Accumulated Other Comprehensive Income	33
NOTE 1 Description of Business	10	NOTE 20	Stock-Based Compensation Plans	33
NOTE 2 Regulation	11	NOTE 21	Other Income, Net	36
NOTE 3 Summary of Significant Accounting Policies	13	NOTE 22	Income Taxes	37
NOTE 4 Segmented Information	19	NOTE 23	Employee Future Benefits	38
NOTE 5 Revenue	21	NOTE 24	Supplementary Cash Flow Information	42
NOTE 6 Accounts Receivable and Other Current Assets	22	NOTE 25	Fair Value of Financial Instruments and Risk Management ...	42
NOTE 7 Inventories	22	NOTE 26	Commitments and Contingencies	46
NOTE 8 Regulatory Assets and Liabilities	23			

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, 2021, 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, 2021, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2021 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, 2021. Deloitte LLP issued an unqualified opinion for both audits.

February 10, 2022

/s/ David G. Hutchens

David G. Hutchens

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

/s/ Jocelyn H. Perry

Jocelyn H. Perry

Executive Vice President, Chief Financial Officer, Fortis Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, 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, 2021, 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 10, 2022, 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.

Consolidated Financial Statements

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

/s/ Deloitte LLP

Deloitte LLP

Chartered Professional Accountants

St. John's, Canada

February 10, 2022

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, 2021, 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, 2021, 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, 2021, of the Corporation and our report dated February 10, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte LLP

Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 10, 2022

Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

	2021	2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 131	\$ 249
Accounts receivable and other current assets (Note 6)	1,511	1,369
Prepaid expenses	116	102
Inventories (Note 7)	478	422
Regulatory assets (Note 8)	492	470
Total current assets	2,728	2,612
Other assets (Note 9)	955	670
Regulatory assets (Note 8)	3,097	3,118
Property, plant and equipment, net (Note 10)	37,816	35,998
Intangible assets, net (Note 11)	1,343	1,291
Goodwill (Note 12)	11,720	11,792
Total assets	\$ 57,659	\$ 55,481
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	\$ 247	\$ 132
Accounts payable and other current liabilities (Note 13)	2,570	2,321
Regulatory liabilities (Note 8)	357	441
Current installments of long-term debt (Note 14)	1,628	1,254
Total current liabilities	4,802	4,148
Regulatory liabilities (Note 8)	2,865	2,662
Deferred income taxes (Note 22)	3,627	3,344
Long-term debt (Note 14)	23,707	23,113
Finance leases (Note 15)	333	331
Other liabilities (Note 16)	1,409	1,599
Total liabilities	36,743	35,197
Commitments and contingencies (Note 26)		
Equity		
Common shares ⁽¹⁾	14,237	13,819
Preference shares (Note 18)	1,623	1,623
Additional paid-in capital	10	11
Accumulated other comprehensive (loss) income (Note 19)	(40)	34
Retained earnings	3,458	3,210
Shareholders' equity	19,288	18,697
Non-controlling interests	1,628	1,587
Total equity	20,916	20,284
Total liabilities and equity	\$ 57,659	\$ 55,481

⁽¹⁾ No par value. Unlimited authorized shares. 474.8 million and 466.8 million issued and outstanding as at December 31, 2021 and 2020, respectively

Approved on Behalf of the Board

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

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

See accompanying Notes to Consolidated Financial Statements

Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)

	2021	2020
Revenue (Note 5)	\$ 9,448	\$ 8,935
Expenses		
Energy supply costs	2,951	2,562
Operating expenses	2,523	2,437
Depreciation and amortization	1,505	1,428
Total expenses	6,979	6,427
Operating income	2,469	2,508
Other income, net (Note 21)	173	154
Finance charges	1,003	1,042
Earnings before income tax expense	1,639	1,620
Income tax expense (Note 22)	234	231
Net earnings	\$ 1,405	\$ 1,389
Net earnings attributable to:		
Non-controlling interests	\$ 111	\$ 115
Preference equity shareholders	63	65
Common equity shareholders	1,231	1,209
	\$ 1,405	\$ 1,389
Earnings per common share (Note 17)		
Basic	\$ 2.61	\$ 2.60
Diluted	\$ 2.61	\$ 2.60

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)

	2021	2020
Net earnings	\$ 1,405	\$ 1,389
Other comprehensive loss		
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of \$2 million and \$3 million, respectively	(93)	(311)
Other, net of income tax expense (recovery) of \$3 million and \$(9) million, respectively	8	(27)
	(85)	(338)
Comprehensive income	\$ 1,320	\$ 1,051
Comprehensive income attributable to:		
Non-controlling interests	\$ 100	\$ 79
Preference equity shareholders	63	65
Common equity shareholders	1,157	907
	\$ 1,320	\$ 1,051

See accompanying Notes to Consolidated Financial Statements

Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the year ended December 31 (in millions of Canadian dollars)

	2021	2020
Operating activities		
Net earnings	\$ 1,405	\$ 1,389
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	1,313	1,282
Amortization - intangible assets	136	131
Amortization - other	56	15
Deferred income tax expense (Note 22)	147	226
Equity component, allowance for funds used during construction (Note 21)	(77)	(78)
Other	71	170
Change in working capital (Note 24)	(144)	(434)
Cash from operating activities	2,907	2,701
Investing activities		
Additions to property, plant and equipment	(3,189)	(3,857)
Additions to intangible assets	(197)	(182)
Contributions in aid of construction	93	68
Other	(195)	(161)
Cash used in investing activities	(3,488)	(4,132)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	1,324	3,470
Repayments of long-term debt and finance leases	(634)	(1,251)
Borrowings under committed credit facilities	5,082	5,648
Repayments under committed credit facilities	(4,749)	(5,299)
Net change in short-term borrowings	115	(413)
Issue of common shares, net of costs, and dividends reinvested	60	58
Dividends		
Common shares, net of dividends reinvested	(608)	(786)
Preference shares	(63)	(65)
Subsidiary dividends paid to non-controlling interests	(58)	(65)
Other	(18)	30
Cash from financing activities	451	1,327
Effect of exchange rate changes on cash and cash equivalents	12	(17)
Change in cash and cash equivalents	(118)	(121)
Cash and cash equivalents, beginning of year	249	370
Cash and cash equivalents, end of year	\$ 131	\$ 249

Supplementary Cash Flow Information (Note 24)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

<i>For the years ended December 31 (in millions of Canadian dollars, except share numbers)</i>	Common Shares (# millions)	Common Shares	Preference Shares (Note 18)	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) (Note 19)	Retained Earnings	Non- Controlling Interests	Total Equity
As at December 31, 2020	466.8	\$ 13,819	\$ 1,623	\$ 11	\$ 34	\$ 3,210	\$ 1,587	\$ 20,284
Net earnings	—	—	—	—	—	1,294	111	1,405
Other comprehensive loss	—	—	—	—	(74)	—	(11)	(85)
Common shares issued	8.0	418	—	(2)	—	—	—	416
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(58)	(58)
Dividends declared on common shares (\$2.08 per share)	—	—	—	—	—	(983)	—	(983)
Dividends on preference shares	—	—	—	—	—	(63)	—	(63)
Other	—	—	—	1	—	—	(1)	—
As at December 31, 2021	474.8	\$ 14,237	\$ 1,623	\$ 10	\$ (40)	\$ 3,458	\$ 1,628	\$ 20,916
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

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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 3,485 megawatts ("MW"), including 53 MW of solar capacity and 252 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

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

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

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

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

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

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

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

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCl consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 94 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

1. DESCRIPTION OF BUSINESS (cont'd)

Non-Regulated

Energy Infrastructure: Long-term contracted generation assets in Belize and the Aitken Creek natural gas storage facility ("Aitken Creek") in British Columbia. Generation assets in Belize consist of three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary 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.

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

2. REGULATION

General

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

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a 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).

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

2. REGULATION (cont'd)

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE ⁽¹⁾ (%)		Significant Features
			2021	2020	
ITC ⁽²⁾	Federal Energy Regulatory Commission ("FERC")	60.0	10.77	10.77	Cost-based formula rates, with annual true-up mechanism ⁽³⁾ Incentive adders
TEP	Arizona Corporation Commission ("ACC") ⁽⁴⁾	53.0	9.15	9.75	COS regulation Historical test year
	FERC	⁽⁵⁾	⁽⁵⁾	⁽⁵⁾	Formula transmission rates
UNS Electric	ACC	52.8	9.50	9.50	
UNS Gas	ACC	50.8	9.75	9.75	
Central Hudson ⁽⁶⁾	New York State Public Service Commission ("PSC")	50.0	9.00	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 ⁽⁷⁾
FortisBC Electric	BCUC	40.0	9.15	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	8.50	8.50	PBR ⁽⁸⁾
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 ⁽⁹⁾	Ontario Energy Board	40.0	8.52-9.30	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities ⁽¹⁰⁾	Utility Regulation and Competition Office	N/A	6.00-8.00	6.75-8.75	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI ⁽¹¹⁾	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 ITC Transmission, METC, and ITC Midwest. See "Significant Regulatory Developments" below

⁽³⁾ Annual true-up collected or refunded in rates within a two-year period

⁽⁴⁾ Effective January 1, 2021, an approved ROE of 9.15% with a 0.20% return on the fair value increment. The common equity component of capital structure for 2020 was 50%

⁽⁵⁾ The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio. See "Significant Regulatory Developments" below

⁽⁶⁾ Allowed common equity percentage is updated annually on July 1st. See "Significant Regulatory Developments" below

⁽⁷⁾ Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below

⁽⁸⁾ 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. See "Significant Regulatory Developments" below

⁽⁹⁾ 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

⁽¹⁰⁾ 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

⁽¹¹⁾ Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037

Significant Regulatory Developments

ITC

Transmission Incentives: In April 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released in March 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for existing RTO members that have been members longer than three years, like ITC. In June 2021, ITC filed its comments on the supplemental NOPR supporting the continuation of the ROE incentive adder for RTO members. The timeline for FERC to issue a final rule in this proceeding as well as the likely outcome and potential impacts to Fortis cannot be determined at this time.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

2. REGULATION (cont'd)

UNS Energy

FERC Rate Case: In 2019, FERC issued an order accepting formula transmission rates proposed by TEP, subject to refund following hearing and settlement procedures. A settlement in principle was reached in August 2021, and a settlement agreement including an ROE of 9.79% was filed with FERC in December 2021. Until conclusion of the proceeding, customer rates continue to be charged under the 2019 FERC order and remain subject to refund pending the final order. The timing and outcome of this proceeding remains unknown.

Central Hudson

General Rate Application: In November 2021, the PSC approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and a common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year. The three-year rate plan also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, the recovery of finance charges which had not been billed to customers since the second quarter of 2020, as well as initiatives to support New York State's climate goals.

FortisBC Energy and FortisBC Electric

Generic Cost of Capital ("GCOC") Proceeding: In January 2021, the BCUC announced the initiation of a GCOC proceeding including a review of the common equity component of capital structure and the allowed ROE. The timing and outcome of this proceeding, including the effective date of any change in the cost of capital for 2022 or beyond, remains unknown.

FortisAlberta

2022 GCOC Proceeding: In March 2021, the AUC concluded the 2022 GCOC proceeding and extended the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2022.

2023 COS Application: The final year of FortisAlberta's second PBR term is 2022. In June 2021, the AUC issued a decision confirming the approach to be adopted by Alberta distribution utilities for the COS rebasing year in 2023. In November 2021, FortisAlberta filed its 2023 COS application and a decision is expected in the third quarter of 2022.

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. The AUC is considering extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. Comments on this proposal are due in February 2022 and a decision is expected in the first quarter of 2022. The GCOC proceeding for 2024 and beyond is expected to commence in the third quarter of 2022, with a decision expected in 2023.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta will submit comments with respect to the design of the third PBR term in 2022 and a decision from the AUC is expected in 2023.

Independent System Operator Tariff Proceeding: In April 2021, the AUC issued a decision confirming that distribution facility owners, such as FortisAlberta, will no longer be permitted to earn a return on contributions made to the Alberta Electric System Operator ("AESO") on a prospective basis from the date of the decision. Contributions made prior to that date are not impacted. The decision did not have a material financial impact on the Corporation in 2021 and it is not expected to materially impact future periods. In January 2022, the Alberta Court of Appeal granted a full appeal on this matter. In doing so, the Alberta Court of Appeal also permitted a related appeal regarding the legality of the AUC's AESO customer contribution policy. FortisAlberta will fully participate in the appeal regarding the legality of the AESO customer contribution policy and will closely monitor the proceeding related to earned returns on future AESO contributions.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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

These consolidated financial statements include the accounts of the Corporation and its subsidiaries. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with U.S. GAAP for rate-regulated entities.

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

Allowance for Credit Losses

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

Inventories

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

Regulatory Assets and Liabilities

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

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

Investments

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

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

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2021 totalled \$39 million (2020 - \$41 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 21). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta, through December 31, 2020, the cost of PPE includes contributions to AESO toward funding the construction of transmission facilities (Note 2).

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

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

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2021 ranged from 0.9% to 39.8% (2020 - 0.9% to 39.8%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.6% for 2021 (2020 - 2.5%).

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

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

(years)	2021		2020	
	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	18-95	38
Transmission				
Electric	20-90	42	20-90	43
Gas	10-85	35	10-85	35
Generation	5-95	23	1-85	24
Other	3-70	13	2-70	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 2021 (2020 – 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.

(years)	2021		2020	
	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	3-15	4	3-15	4
Land, transmission and water rights	34-90	55	43-90	56
Other	10-100	11	10-100	12

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

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the total undiscounted cash flows expected to be generated by the asset may be below carrying value. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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 U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

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 probable.

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 and PSUs, as well as RSUs issued through 2019 represent cash-settled awards. Effective January 1, 2020, new RSU issuances represent cash or share-settled awards, depending on settlement elections and the share ownership requirements of the executive. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2021 was \$61.08 (2020 - \$52.36). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

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

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a U.S. dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2021 was US\$1.00=CA\$1.26 (2020 - US\$1.00=CA\$1.27).

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\$1.25 for 2021 (2020 - US\$1.00=CA\$1.34).

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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 U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These derivatives are measured at fair value with changes thereto recognized in earnings.

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

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

Derivatives Designated as Hedges

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

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

Presentation of Derivatives

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

Income Taxes

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

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

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

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

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately \$4.1 billion as at December 31, 2021 (2020 - \$3.4 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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

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.

Use of Accounting Estimates

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

Future Accounting Pronouncements

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

4. SEGMENTED INFORMATION

General

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

Related-Party and Inter-Company Transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2021 or 2020.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of \$38 million in 2021 (2020 - \$25 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2021, accounts receivable included \$22 million due from Belize Electricity (2020 - \$28 million).

Fortis periodically provides short-term financing, the impacts of which are eliminated on consolidation, to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. In October 2021, Fortis entered into a non-revolving term credit facility with UNS Energy to lend a maximum of US\$175 million, maturing December 2022. As at December 31, 2021, inter-segment loans of \$126 million were outstanding related to this agreement. Interest charged on inter-segment loans was not material in 2021 and 2020.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

4. SEGMENTED INFORMATION (cont'd)

(\$ millions)	Regulated								Non-Regulated		Inter-segment eliminations	Total
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Sub-total	Energy Infrastructure	Corporate and Other		
Year ended December 31, 2021												
Revenue	1,691	2,334	1,000	1,715	644	468	1,498	9,350	98	—	—	9,448
Energy supply costs	—	919	285	713	—	136	895	2,948	3	—	—	2,951
Operating expenses	466	648	498	355	157	128	201	2,453	33	37	—	2,523
Depreciation and amortization	291	345	91	281	231	65	181	1,485	17	3	—	1,505
Operating income	934	422	126	366	256	139	221	2,464	45	(40)	—	2,469
Other income, net	42	41	34	12	2	5	5	141	1	31	—	173
Finance charges	300	120	46	144	106	73	71	860	—	143	—	1,003
Income tax expense	156	51	21	48	11	12	21	320	8	(94)	—	234
Net earnings	520	292	93	186	141	59	134	1,425	38	(58)	—	1,405
Non-controlling interests	94	—	—	1	—	—	16	111	—	—	—	111
Preference share dividends	—	—	—	—	—	—	—	—	—	63	—	63
Net earnings attributable to common equity shareholders	426	292	93	185	141	59	118	1,314	38	(121)	—	1,231
Additions to property, plant and equipment and intangible assets	1,046	710	291	475	389	134	321	3,366	20	—	—	3,386
As at December 31, 2021												
Goodwill	7,755	1,746	570	913	228	235	246	11,693	27	—	—	11,720
Total assets	21,020	11,126	4,356	8,135	5,201	2,540	4,357	56,735	777	295	(148)	57,659
Year ended December 31, 2020												
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
Additions to property, plant and equipment and intangible assets	1,182	1,200	339	471	420	135	273	4,020	19	—	—	4,039
As at December 31, 2020												
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

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

5. REVENUE

(\$ millions)	2021	2020
Electric and gas revenue		
United States		
ITC	1,694	1,726
UNS Energy	2,071	2,019
Central Hudson	962	941
Canada		
FortisBC Energy	1,645	1,336
FortisAlberta	622	580
FortisBC Electric	404	358
Newfoundland Power	701	707
Maritime Electric	223	215
FortisOntario	211	222
Caribbean		
Caribbean Utilities	248	238
FortisTCL	89	77
Total electric and gas revenue	8,870	8,419
Other services revenue ⁽¹⁾	382	325
Revenue from contracts with customers	9,252	8,744
Alternative revenue ⁽²⁾	(18)	64
Other revenue	214	127
Total revenue	9,448	8,935

⁽¹⁾ Includes \$260 million and \$227 million from regulated operations for 2021 and 2020, respectively

⁽²⁾ 2020 includes a \$40 million favourable base ROE adjustment associated with the May 2020 FERC decision, which set the all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator, Inc. "MISO" region at 10.77%

Revenue from Contracts with Customers

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

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

Alternative Revenue

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

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

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

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

Other Revenue

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

<i>(\$ millions)</i>	2021	2020
Trade accounts receivable	621	595
Unbilled accounts receivable	701	571
Allowance for credit losses	(53)	(64)
	1,269	1,102
Income tax receivable	—	72
Other ⁽¹⁾	242	195
	1,511	1,369

⁽¹⁾ Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 25)

Allowance for Credit Losses

The allowance for credit losses changed as follows.

<i>(\$ millions)</i>	2021	2020
Balance, beginning of year	(64)	(35)
Credit loss expensed	(7)	(36)
Credit loss deferral	—	(6)
Write-offs, net of recoveries	18	14
Foreign exchange	—	(1)
Balance, end of year	(53)	(64)

7. INVENTORIES

<i>(\$ millions)</i>	2021	2020
Materials and supplies	318	297
Gas and fuel in storage	131	101
Coal inventory	29	24
	478	422

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

8. REGULATORY ASSETS AND LIABILITIES

(\$ millions)	2021	2020
Regulatory assets		
Deferred income taxes (Notes 3 and 22)	1,806	1,697
Employee future benefits (Notes 3 and 23)	388	588
Deferred energy management costs ⁽¹⁾	384	334
Rate stabilization and related accounts ⁽²⁾	339	213
Deferred lease costs ⁽³⁾	127	122
Manufactured gas plant site remediation deferral (Note 16)	96	107
Generation early retirement costs ⁽⁴⁾	48	55
Derivatives (Notes 3 and 25)	20	73
Other regulatory assets ⁽⁵⁾	381	399
Total regulatory assets	3,589	3,588
Less: Current portion	(492)	(470)
Long-term regulatory assets	3,097	3,118
Regulatory liabilities		
Deferred income taxes (Notes 3 and 22)	1,289	1,361
Future cost of removal (Note 3)	1,217	1,206
Employee future benefits (Notes 3 and 23)	196	43
Rate stabilization and related accounts ⁽²⁾	116	104
Renewable energy surcharge ⁽⁶⁾	107	100
Energy efficiency liability ⁽⁷⁾	83	83
Derivatives (Notes 3 and 25)	52	17
Other regulatory liabilities ⁽⁵⁾	162	189
Total regulatory liabilities	3,222	3,103
Less: Current portion	(357)	(441)
Long-term regulatory liabilities	2,865	2,662

⁽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. In 2020, the ACC approved the recovery of the retirement costs of Navajo and Sundt over a 10-year period.

⁽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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

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.

Regulatory assets not earning a return: (i) totalled \$1,727 million and \$1,678 million as at December 31, 2021 and 2020, 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

<i>(\$ millions)</i>	2021	2020
Employee future benefits (Note 23)	259	66
Supplemental Executive Retirement Plan ("SERP")	165	155
RECs (Note 8)	112	106
Other investments	86	66
Equity investment - Belize Electricity	80	80
Deferred compensation plan	42	36
Operating leases (Note 15)	40	40
Derivatives	40	4
Equity investment - Wataynikaneyap Partnership	12	12
Other	119	105
	955	670

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 25).

10. PROPERTY, PLANT AND EQUIPMENT

<i>(\$ millions)</i>	Cost	Accumulated Depreciation	Net Book Value
2021			
Distribution			
Electric	12,321	(3,359)	8,962
Gas	5,838	(1,504)	4,334
Transmission			
Electric	17,104	(3,610)	13,494
Gas	2,453	(756)	1,697
Generation	7,014	(2,691)	4,323
Other	4,362	(1,454)	2,908
Assets under construction	1,759	—	1,759
Land	339	—	339
	51,190	(13,374)	37,816

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

<i>(\$ millions)</i>	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

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

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

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

Other assets include buildings, equipment, vehicles, inventory, information technology assets and assets associated with natural gas storage at Aitken Creek.

As at December 31, 2021, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy.

The cost of PPE under finance lease as at December 31, 2021 was \$323 million (2020 - \$322 million) and related accumulated depreciation was \$113 million (2020 - \$111 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, 2021, interests in jointly owned facilities consisted of the following.

<i>(\$ millions, except as indicated)</i>	Ownership (%)	Cost	Accumulated Depreciation	Net Book Value
Transmission Facilities	1.0-80.0	958	(290)	668
Springerville Common Facilities	86.0	504	(262)	242
San Juan Unit 1 ("San Juan")	50.0	361	(340)	21
Springerville Coal Handling Facilities	83.0	264	(120)	144
Four Corners Units 4 and 5 ("Four Corners")	7.0	243	(102)	141
Gila River Common Facilities	50.0	109	(38)	71
Luna Energy Facility ("Luna")	33.3	76	(4)	72
		2,515	(1,156)	1,359

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

11. INTANGIBLE ASSETS

<i>(\$ millions)</i>	Cost	Accumulated Amortization	Net Book Value
2021			
Computer software	952	(518)	434
Land, transmission and water rights	941	(154)	787
Other	113	(69)	44
Assets under construction	78	—	78
	2,084	(741)	1,343
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

Included in the cost of land, transmission and water rights as at December 31, 2021 was \$137 million (2020 - \$136 million) not subject to amortization. Amortization expense was \$136 million for 2021 (2020 - \$131 million). Amortization is estimated to average approximately \$82 million for each of the next five years.

12. GOODWILL

<i>(\$ millions)</i>	2021	2020
Balance, beginning of year	11,792	12,004
Foreign currency translation impacts ⁽¹⁾	(72)	(212)
Balance, end of year	11,720	11,792

⁽¹⁾ Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCL, whose functional currency is the U.S. dollar

No goodwill impairment was recognized by the Corporation in 2021 or 2020.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

<i>(\$ millions)</i>	2021	2020
Trade accounts payable	774	707
Employee compensation and benefits payable	283	248
Gas and fuel cost payable	269	188
Dividends payable	259	241
Accrued taxes other than income taxes	238	224
Customer and other deposits	222	214
Interest payable	218	215
Derivatives (Note 25)	43	56
Income taxes payable	31	—
Employee future benefits (Note 23)	26	26
Manufactured gas plant site remediation (Note 16)	13	31
Other	194	171
	2,570	2,321

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

14. LONG-TERM DEBT

<i>(\$ millions)</i>	Maturity Date	2021	2020
ITC			
Secured U.S. First Mortgage Bonds - 4.31% weighted average fixed rate (2020 - 4.31%)	2024-2055	2,736	2,755
Secured U.S. Senior Notes - 3.90% weighted average fixed rate (2020 - 4.00%)	2040-2055	1,011	923
Unsecured U.S. Senior Notes - 3.61% weighted average fixed rate (2020 - 3.61%)	2022-2043	4,108	4,136
Unsecured U.S. Shareholder Note - 6.00% fixed rate (2020 - 6.00%)	2028	252	253
UNS Energy			
Unsecured U.S. Tax-Exempt Bonds - 4.34% weighted average fixed and variable rate (2020 - 4.34%)	2029-2030	359	362
Unsecured U.S. Fixed Rate Notes - 3.62% weighted average fixed rate (2020 - 3.86%)	2023-2051	2,780	2,704
Central Hudson			
Unsecured U.S. Promissory Notes - 3.83% weighted average fixed and variable rate (2020 - 3.94%)	2022-2060	1,177	1,078
FortisBC Energy			
Unsecured Debentures - 4.61% weighted average fixed rate (2020 - 4.72%)	2026-2050	3,145	2,995
FortisAlberta			
Unsecured Debentures - 4.49% weighted average fixed rate (2020 - 4.49%)	2024-2052	2,360	2,360
FortisBC Electric			
Secured Debentures - 8.80% fixed rate (2020 - 8.80%)	2023	25	25
Unsecured Debentures - 4.77% weighted average fixed rate (2020 - 4.87%)	2035-2050	760	785
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.61% weighted average fixed rate (2020 - 5.61%)	2022-2060	627	634
Secured First Mortgage Bonds - 5.31% weighted average fixed rate (2020 - 5.66%)	2025-2061	260	220
Unsecured Senior Notes - 4.45% weighted average fixed rate (2020 - 4.45%)	2041-2048	152	152
Unsecured U.S. Senior Loan Notes and Bonds - 4.36% weighted average fixed and variable rate (2020 - 4.41%)	2022-2049	609	648
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes - 3.82% weighted average fixed rate (2020 - 3.81%)	2023-2044	2,509	2,685
Unsecured Debentures - 6.50% fixed rate (2020 - 6.50%)	2039	200	200
Unsecured Senior Notes - 2.52% weighted average fixed rate (2020 - 2.85%)	2023-2028	1,000	500
Long-term classification of credit facility borrowings		1,305	980
Fair value adjustment - ITC acquisition		107	119
Total long-term debt (Note 25)		25,482	24,514
Less: Deferred financing costs and debt discounts		(147)	(147)
Less: Current installments of long-term debt		(1,628)	(1,254)
		23,707	23,113

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

14. LONG-TERM DEBT (cont'd)

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

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

Certain long-term debt agreements have covenants that provide that the Corporation shall not declare, pay or make any restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances in 2021	Month Issued	Interest Rate (%)	Maturity	Amount (\$ millions)	Use of Proceeds
ITC					
Series A secured senior notes ⁽¹⁾	August	2.90	2051	US 75	(2)
UNS Energy					
Unsecured senior notes	May	3.25	2051	US 325	(3)(4)
Central Hudson					
Unsecured senior notes	March	3.29	2051	US 75	(3)(4)
Unsecured senior notes	October	3.22	2051	US 55	(3)(5)
FortisBC Energy					
Unsecured debentures	April	2.42	2031	150	(5)
Maritime Electric					
Secured first mortgage bonds	December	3.40	2051	40	(5)
Fortis					
Unsecured senior notes	May	2.18	2028	500	(3)(4)(5)

⁽¹⁾ US\$75 million Series B secured senior notes were priced at 3.05% with issuance expected in May 2022

⁽²⁾ Fund or refinance a portfolio of eligible green projects

⁽³⁾ General corporate purposes

⁽⁴⁾ Repay maturing long-term debt

⁽⁵⁾ Repay credit facility borrowings

In January 2022, ITC issued 30-year US\$150 million secured first mortgage bonds at 2.93%. The net proceeds are expected to be used to repay credit facility borrowings, fund or refinance a portfolio of eligible green projects, fund capital expenditures and for other general corporate purposes.

In January 2022, Central Hudson issued 5-year US\$50 million unsecured senior notes at 2.37% and 7-year US\$60 million unsecured senior notes at 2.59%. The net proceeds are expected to be used to repay maturing long-term debt and for general corporate purposes.

Long-Term Debt Repayments

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

(\$ millions)	Total
2022	1,628
2023	1,275
2024	1,750
2025	101
2026	2,595
Thereafter	18,133
	25,482

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. In May 2021, the Corporation issued \$500 million unsecured senior notes as shown above and, as at December 31, 2021, \$1.5 billion remained available under the short-form base shelf prospectus.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

14. LONG-TERM DEBT (cont'd)

Credit Facilities

(\$ millions)	Regulated Utilities	Corporate and Other	2021	2020
Total credit facilities	3,466	1,380	4,846	5,581
Credit facilities utilized:				
Short-term borrowings ⁽¹⁾	(247)	—	(247)	(132)
Long-term debt (including current portion) ⁽²⁾	(1,019)	(286)	(1,305)	(980)
Letters of credit outstanding	(70)	(45)	(115)	(130)
Credit facilities unutilized	2,130	1,049	3,179	4,339

⁽¹⁾ The weighted average interest rate was approximately 0.6% (2020 - 0.8%).

⁽²⁾ The weighted average interest rate was approximately 0.9% (2020 - 0.9%). The current portion was \$888 million (2020 - \$651 million).

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the total facilities. Approximately \$4.6 billion of the total credit facilities are committed facilities with maturities ranging from 2022 through 2026.

Consolidated credit facilities of approximately \$4.8 billion as at December 31, 2021 are itemized below. In April 2021, the Corporation's unsecured \$500 million revolving one-year term committed credit facility expired and was not renewed. In October 2021, UNS Energy terminated a US\$150 million revolving credit facility and entered into an arrangement with Fortis (Note 4).

(\$ millions)	Amount	Maturity
Unsecured committed revolving credit facilities		
Regulated utilities		
ITC ⁽¹⁾	US 900	2024
UNS Energy	US 375	2026
Central Hudson	US 200	2025
FortisBC Energy	700	2026
FortisAlberta	250	2026
FortisBC Electric	150	2026
Other Electric	215	⁽²⁾
Other Electric	US 70	2025
Corporate and Other	1,350	⁽³⁾
Other facilities		
Regulated utilities		
Central Hudson - uncommitted credit facility	US 30	n/a
FortisBC Energy - uncommitted credit facility	55	2023
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	2022
Corporate and Other - unsecured non-revolving facility	30	n/a

⁽¹⁾ ITC also has a US\$400 million commercial paper program, under which US\$155 million was outstanding as at December 31, 2021 (2020 - US\$67 million), as reported in short-term borrowings.

⁽²⁾ \$50 million in 2024, \$65 million in 2024 and \$100 million in 2026

⁽³⁾ \$50 million in 2023 and \$1.3 billion in 2026

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 20 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 34 years.

Leases were presented on the consolidated balance sheets as follows.

(\$ millions)	2021	2020
Operating leases		
Other assets	40	40
Accounts payable and other current liabilities	(8)	(7)
Other liabilities	(32)	(33)
Finance leases ⁽¹⁾		
Regulatory assets	127	122
PPE, net	210	211
Accounts payable and other current liabilities	(4)	(2)
Finance leases	(333)	(331)

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

The components of lease expense were as follows.

(\$ millions)	2021	2020
Operating lease cost	8	10
Finance lease cost:		
Amortization	2	14
Interest	32	34
Variable lease cost	19	20
Total lease cost	61	78

As at December 31, 2021, the present value of minimum lease payments was as follows.

(\$ millions)	Operating Leases	Finance Leases	Total
2022	8	35	43
2023	7	34	41
2024	6	34	40
2025	5	34	39
2026	3	35	38
Thereafter	20	1,030	1,050
	49	1,202	1,251
Less: Imputed interest	(9)	(865)	(874)
Total lease obligations	40	337	377
Less: Current installments	(8)	(4)	(12)
	32	333	365

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

15. LEASES (cont'd)

Supplemental lease information follows.

<i>(\$ millions, except as indicated)</i>	2021	2020
Weighted average remaining lease term (years)		
Operating leases	10	10
Finance leases	34	35
Weighted average discount rate (%)		
Operating leases	3.8	4.0
Finance leases	5.1	5.1
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	(8)	(10)
Operating cash flows used for finance leases	—	(2)
Financing cash flows used for finance leases	(2)	(25)
Investing cash flows used for finance leases	—	(87)

16. OTHER LIABILITIES

<i>(\$ millions)</i>	2021	2020
Employee future benefits (Note 23)	740	905
AROs (Note 3)	184	130
Customer and other deposits	99	132
Stock-based compensation plans (Note 20)	96	86
Manufactured gas plant site remediation ⁽¹⁾	83	69
Deferred compensation plan (Note 9)	50	43
Mine reclamation obligations ⁽²⁾	44	47
Retail energy contract ⁽³⁾	40	46
Operating leases	32	33
Derivatives (Note 25)	7	50
Other	34	58
	1,409	1,599

⁽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, 2021, an obligation of \$91 million was recognized, including a current portion of \$8 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 \$56 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⁾ In 2020, FortisAlberta entered into an eight-year agreement with an existing retail energy provider to continue to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment which is being amortized to revenue over the life of the agreement.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

17. EARNINGS PER COMMON SHARE

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

	2021			2020		
	Net Earnings to Common Shareholders (\$ millions)	Weighted Average Shares (# millions)	EPS (\$)	Net Earnings to Common Shareholders (\$ millions)	Weighted Average Shares (# millions)	EPS (\$)
Basic EPS	1,231	470.9	2.61	1,209	464.8	2.60
Potential dilutive effect of stock options	—	0.5	—	—	0.6	—
Diluted EPS	1,231	471.4	2.61	1,209	465.4	2.60

18. PREFERENCE SHARES

Authorized

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

Issued and Outstanding

	2021		2020	
	Number of Shares (thousands)	Amount (\$ millions)	Number of Shares (thousands)	Amount (\$ millions)
First Preference Shares				
Series F	5,000	122	5,000	122
Series G	9,200	225	9,200	225
Series H	7,665	188	7,665	188
Series I	2,335	57	2,335	57
Series J	8,000	196	8,000	196
Series K	10,000	244	10,000	244
Series M	24,000	591	24,000	591
	66,200	1,623	66,200	1,623

Characteristics of the first preference shares are as follows.

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

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

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

⁽³⁾ On the redemption and/or conversion option date, and on each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying \$25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.

⁽⁴⁾ On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Redeemable first preference shares of a specified series.

⁽⁵⁾ The 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.

⁽⁶⁾ 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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

18. PREFERENCE SHARES (cont'd)

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.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

<i>(\$ millions)</i>	Opening Balance	Net Change	Ending Balance
2021			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	377	(104)	273
Hedges of net investments in foreign operations	(299)	23	(276)
Income tax expense	(6)	(2)	(8)
	72	(83)	(11)
Other			
Cash flow hedges (Note 25)	(4)	(1)	(5)
Unrealized employee future benefits (losses) gains (Note 23)	(49)	13	(36)
Income tax recovery (expense)	15	(3)	12
	(38)	9	(29)
Accumulated other comprehensive income	34	(74)	(40)
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 25)	17	(21)	(4)
Unrealized employee future benefits losses (Note 23)	(38)	(11)	(49)
Income tax recovery	6	9	15
	(15)	(23)	(38)
Accumulated other comprehensive income	336	(302)	34

20. 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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

The following options were granted in 2021 and 2020.

	2021	2020
Options granted (thousands)	431	686
Exercise price (\$) ⁽¹⁾	50.33	58.40
Grant date fair value (\$)	4.91	4.20
Valuation assumptions:		
Dividend yield (%) ⁽²⁾	3.8	3.7
Expected volatility (%) ⁽³⁾	20.0	15.8
Risk-free interest rate (%) ⁽⁴⁾	0.9	1.2
Weighted average expected life (years) ⁽⁵⁾	5.0	5.2

⁽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 2021.

	Total Options		Non-vested Options ⁽¹⁾	
	Number of Options	Weighted Average Exercise Price (\$)	Number of Options	Weighted Average Grant Date Fair Value (\$)
<i>(thousands, except as indicated)</i>				
Options outstanding, beginning of year	3,262	45.26	1,772	3.81
Granted	431	50.33	431	4.91
Exercised	(777)	40.80	n/a	n/a
Vested	n/a	n/a	(715)	3.67
Cancelled/Forfeited	—	—	—	—
Options outstanding, end of year	2,916	47.20	1,488	4.20
Options vested, end of year ⁽²⁾	1,428	42.76		

⁽¹⁾ As at December 31, 2021, there was \$6 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, 2021, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of \$26 million.

The following table summarizes additional stock option information.

	2021	2020
<i>(\$ millions)</i>		
Stock options exercised:		
Cash received for exercise price	32	32
Intrinsic value realized by employees	11	15

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

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.

	2021	2020
Number of units (thousands)		
Beginning of year	147	165
Granted	30	25
Notional dividends reinvested	6	6
Paid out	—	(49)
End of year	183	147

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2021 or 2020.

PSU Plans

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

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

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

The following table summarizes information related to PSUs.

	2021	2020
Number of units (thousands)		
Beginning of year	1,976	2,118
Granted	587	586
Notional dividends reinvested	60	71
Paid out	(697)	(735)
Cancelled/forfeited	(28)	(64)
End of year	1,898	1,976
Additional information (\$ millions)		
Compensation expense recognized	74	58
Compensation expense unrecognized ⁽¹⁾	33	32
Cash payout	50	54
Accrued liability as at December 31 ⁽²⁾	132	108
Aggregate intrinsic value as at December 31 ⁽³⁾	165	140

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

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

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

RSU Plans

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

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash or, beginning with the 2020 grant, common shares of the Corporation. Effective January 1, 2020, new RSU issuances may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executives' settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

	2021	2020
Number of units (thousands)		
Beginning of year	1,048	1,050
Granted	378	356
Notional dividends reinvested	32	37
Paid out	(371)	(355)
Cancelled/forfeited	(27)	(40)
End of year	1,060	1,048
Additional information (\$ millions)		
Compensation expense recognized	26	20
Compensation expense unrecognized ⁽¹⁾	17	15
Cash payout	21	19
Accrued liability as at December 31 ⁽²⁾	46	39
Aggregate intrinsic value as at December 31 ⁽³⁾	63	54

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

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

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

21. OTHER INCOME, NET

(\$ millions)	2021	2020
Equity component of AFUDC	77	78
Non-service benefit cost	45	31
Derivative gains	30	13
Equity income	7	20
Interest income	5	13
Other	9	(1)
	173	154

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

22. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

<i>(\$ millions)</i>	2021	2020
Gross deferred income tax assets		
Regulatory liabilities	560	527
Tax loss and credit carryforwards	556	494
Employee future benefits	169	175
Other	91	116
	1,376	1,312
Valuation allowance	(23)	(22)
Net deferred income tax asset	1,353	1,290
Gross deferred income tax liabilities		
PPE	(4,571)	(4,253)
Regulatory assets	(283)	(263)
Intangible assets	(126)	(118)
	(4,980)	(4,634)
Net deferred income tax liability	(3,627)	(3,344)

Unrecognized Tax Benefits

<i>(\$ millions)</i>	2021	2020
Beginning of year	33	36
Additions related to current year	2	3
Adjustments related to prior years ⁽ⁱ⁾	(33)	(6)
End of year	2	33

(i) UNS Energy received approval from the Internal Revenue Service to change its accounting method related to an uncertain tax position which resulted in a decrease in uncertain tax benefits.

Unrecognized tax benefits, if recognized, would reduce income tax expense by \$1 million in 2021. Fortis has not recognized interest expense in 2021 and 2020 related to unrecognized tax benefits.

Income Tax Expense

<i>(\$ millions)</i>	2021	2020
Canadian		
Earnings before income tax expense	427	333
Current income tax	84	20
Deferred income tax	(35)	(16)
Total Canadian	49	4
Foreign		
Earnings before income tax expense	1,212	1,287
Current income tax	3	(15)
Deferred income tax	182	242
Total Foreign	185	227
Income tax expense	234	231

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

22. INCOME TAXES (cont'd)

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

<i>(\$ millions, except as indicated)</i>	2021	2020
Earnings before income tax expense	1,639	1,620
Combined Canadian federal and provincial statutory income tax rate (%)	30.0	30.0
Expected federal and provincial taxes at statutory rate	492	486
Decrease resulting from:		
Foreign and other statutory rate differentials	(157)	(145)
AFUDC	(16)	(20)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	(47)	(56)
Items capitalized for accounting purposes but expensed for income tax purposes	(13)	(26)
Other	(25)	(8)
Income tax expense	234	231
Effective tax rate (%)	14.3	14.3

Income Tax Carryforwards

<i>(\$ millions)</i>	Expiring Year	2021
Canadian		
Capital loss	n/a	15
Non-capital loss	2028-2041	308
Other tax credits	2026-2041	2
		325
Unrecognized		(15)
		310
Foreign		
Federal and state net operating loss	2022-2041	3,070
Other tax credits	2023-2041	90
		3,160
Total income tax carryforwards recognized		3,470

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2013 to 2021 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2021 taxation years are still open for audit in United States jurisdictions.

23. EMPLOYEE FUTURE BENEFITS

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

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 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; December 31, 2020 for the Corporation; and December 31, 2021 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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets <i>(weighted average %)</i>	2021 Target Allocation	2021	2020
Equities	47	48	48
Fixed income	46	45	45
Real estate	6	6	6
Cash and other	1	1	1
	100	100	100

Fair Value of Plan Assets

<i>(\$ millions)</i>	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	Total
2021				
Equities	749	1,271	—	2,020
Fixed income	219	1,642	—	1,861
Real estate	—	—	235	235
Private equities	—	—	21	21
Cash and other	10	15	—	25
	978	2,928	256	4,162
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

⁽¹⁾ See Note 25 for a description of the fair value hierarchy.

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

<i>(\$ millions)</i>	2021	2020
Balance, beginning of year	224	229
Return (loss) on plan assets	32	(2)
Foreign currency translation	—	(1)
Purchases, sales and settlements	—	(2)
Balance, end of year	256	224

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status	Defined Benefit Pension Plans		OPEB Plans	
	2021	2020	2021	2020
(\$ millions)				
Change in benefit obligation ⁽¹⁾				
Balance, beginning of year	3,995	3,632	789	712
Service costs	109	98	35	32
Employee contributions	18	17	2	2
Interest costs	98	113	19	22
Benefits paid	(170)	(162)	(25)	(27)
Actuarial (gains) losses	(111)	350	(70)	62
Past service credits/plan amendments	(2)	—	—	(3)
Foreign currency translation	(15)	(53)	(3)	(11)
Balance, end of year ⁽²⁾	3,922	3,995	747	789
Change in value of plan assets				
Balance, beginning of year	3,528	3,208	391	343
Actual return on plan assets	291	444	48	55
Benefits paid	(158)	(155)	(21)	(27)
Employee contributions	18	17	2	2
Employer contributions	55	62	22	28
Foreign currency translation	(12)	(48)	(2)	(10)
Balance, end of year	3,722	3,528	440	391
Funded status	(200)	(467)	(307)	(398)
Balance sheet presentation				
Other assets (Note 9)	204	58	55	8
Other current liabilities (Note 13)	(13)	(13)	(13)	(13)
Other liabilities (Note 16)	(391)	(512)	(349)	(393)
	(200)	(467)	(307)	(398)

⁽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 \$3,586 million as at December 31, 2021 (2020 - \$3,679 million).

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was \$2,188 million compared to plan assets of \$1,799 million (2020 - \$3,290 million and \$2,777 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, 2021, the obligation was \$1,243 million compared to plan assets of \$1,063 million (2020 - \$3,037 million and \$2,741 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was \$398 million compared to plan assets of \$36 million (2020 - \$589 million and \$183 million, respectively).

Net Benefit Cost ⁽¹⁾	Defined Benefit Pension Plans		OPEB Plans	
	2021	2020	2021	2020
(\$ millions)				
Service costs	109	98	35	32
Interest costs	98	113	19	22
Expected return on plan assets	(177)	(176)	(19)	(19)
Amortization of actuarial losses (gains)	36	33	(2)	(5)
Amortization of past service credits/plan amendments	(1)	(1)	(1)	(2)
Regulatory adjustments	(1)	—	3	4
	64	67	35	32

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

23. EMPLOYEE FUTURE BENEFITS (cont'd)

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

(\$ millions)	Defined Benefit Pension Plans		OPEB Plans	
	2021	2020	2021	2020
Unamortized net actuarial losses (gains)	33	42	(5)	(1)
Unamortized past service costs	1	1	7	7
Income tax recovery	(8)	(10)	—	(1)
Accumulated other comprehensive income	26	33	2	5
Net actuarial losses (gains)	260	517	(81)	12
Past service credits	(5)	(7)	(6)	(8)
Other regulatory deferrals	10	13	14	18
	265	523	(73)	22
Regulatory assets (Note 8)	376	523	12	65
Regulatory liabilities (Note 8)	(111)	—	(85)	(43)
Net regulatory assets (liabilities)	265	523	(73)	22

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

(\$ millions)	Defined Benefit Pension Plans		OPEB Plans	
	2021	2020	2021	2020
Current year net actuarial (gains) losses	(10)	9	(4)	1
Amortization of actuarial losses	1	1	—	—
Income tax expense (recovery)	2	(2)	1	—
Total recognized in comprehensive income	(7)	8	(3)	1
Current year net actuarial (gains) losses	(220)	69	(95)	25
Past service credits/plan amendments	—	—	—	(3)
Amortization of actuarial (losses) gains	(35)	(31)	2	5
Amortization of past service credits	2	2	2	3
Foreign currency translation	(2)	(7)	—	—
Regulatory adjustments	(3)	(2)	(4)	(1)
Total recognized in regulatory (liabilities) assets	(258)	31	(95)	29

Significant Assumptions

(weighted average %)	Defined Benefit Pension Plans		OPEB Plans	
	2021	2020	2021	2020
Discount rate during the year ⁽¹⁾	2.60	3.16	2.60	3.22
Discount rate as at December 31	3.00	2.63	2.97	2.64
Expected long-term rate of return on plan assets ⁽²⁾	5.40	5.52	4.88	5.28
Rate of compensation increase	3.30	3.34	—	—
Health care cost trend increase as at December 31 ⁽³⁾	—	—	4.49	4.61

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

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

⁽³⁾ The projected 2022 weighted average health care cost trend rate is 5.75% and is assumed to decrease over the next 11 years to the weighted average ultimate health care cost trend rate of 4.49% in 2032 and thereafter.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments (\$ millions)	Defined Benefit Pension Payments	OPEB Payments
2022	\$ 168	\$ 28
2023	172	29
2024	176	30
2025	181	32
2026	189	33
2027-2031	1,019	175

During 2022, the Corporation expects to contribute \$49 million for defined benefit pension plans and \$27 million for OPEB plans.

In 2021, the Corporation expensed \$44 million (2020 - \$42 million) related to defined contribution pension plans.

24. SUPPLEMENTARY CASH FLOW INFORMATION

(\$ millions)	2021	2020
Cash paid (received) for		
Interest	986	1,027
Income taxes	(13)	(26)
Change in working capital		
Accounts receivable and other current assets	(88)	(84)
Prepaid expenses	(15)	(15)
Inventories	(56)	(36)
Regulatory assets - current portion	(99)	(49)
Accounts payable and other current liabilities	164	(100)
Regulatory liabilities - current portion	(50)	(150)
	(144)	(434)
Non-cash investing and financing activities		
Accrued capital expenditures	432	400
Common share dividends reinvested	356	114
Contributions in aid of construction	13	13

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

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

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2021, unrealized losses of \$20 million (2020 - \$73 million) were recognized as regulatory assets and unrealized gains of \$52 million (2020 - \$17 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2021, unrealized gains of \$21 million (2020 - \$3 million) were recognized in revenue.

Total Return Swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of \$112 million and terms of one to three years expiring at varying dates through January 2024. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized gains of \$17 million (2020 - unrealized losses of \$9 million) were recognized in other income, net.

Foreign Exchange Contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through November 2022 and have a combined notional amount of \$161 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized losses of \$11 million (2020 - unrealized gains of \$11 million) were recognized in other income, net.

Interest Rate Swaps

In 2021, ITC entered into interest rate swaps with a total notional value of US\$375 million to manage the interest rate risk associated with the refinancing of long-term debt due in November 2022. The swaps have five-year terms, include mandatory early termination provisions, and will be terminated no later than the effective date of November 15, 2022. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2021.

Other Investments

ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments include 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. In 2021, unrealized gains of \$9 million (2020 - \$7 million) were recognized in other income, net.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

Recurring Fair Value Measures

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

(\$ millions)	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	Total
As at December 31, 2021				
Assets				
Energy contracts subject to regulatory deferral ⁽²⁾⁽³⁾	—	78	—	78
Energy contracts not subject to regulatory deferral ⁽²⁾	—	16	—	16
Foreign exchange contracts, total return and interest rate swaps ⁽²⁾	23	2	—	25
Other investments ⁽⁴⁾	137	—	—	137
	160	96	—	256
Liabilities				
Energy contracts subject to regulatory deferral ⁽³⁾⁽⁵⁾	—	(46)	—	(46)
Energy contracts not subject to regulatory deferral ⁽⁵⁾	—	(3)	—	(3)
	—	(49)	—	(49)
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)

⁽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

Energy Contracts

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

(\$ millions)	Gross Amount Recognized In Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
As at December 31, 2021				
Derivative assets	94	25	7	62
Derivative liabilities	(49)	(25)	—	(24)
As at December 31, 2020				
Derivative assets	44	26	10	8
Derivative liabilities	(106)	(26)	(9)	(71)

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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

Volume of Derivative Activity

As at December 31, 2021, 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.

	2021	2020
Energy contracts subject to regulatory deferral ⁽¹⁾		
Electricity swap contracts (GWh)	509	522
Electricity power purchase contracts (GWh)	731	2,781
Gas swap contracts (PJ)	151	156
Gas supply contract premiums (PJ)	144	203
Energy contracts not subject to regulatory deferral ⁽¹⁾		
Wholesale trading contracts (GWh)	1,886	1,588
Gas swap contracts (PJ)	29	36

⁽¹⁾ GWh means gigawatt hours and PJ means petajoules

Credit Risk

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

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

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

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 \$59 million as at December 31, 2021 (2020 - \$88 million).

Hedge of Foreign Net Investments

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

As at December 31, 2021, US\$2.2 billion (2020 - US\$2.3 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US\$10.8 billion (2020 - US\$10.2 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, 2021, the carrying value of long-term debt, including current portion, was \$25.5 billion (2020 - \$24.5 billion) compared to an estimated fair value of \$28.8 billion (2020 - \$29.1 billion).

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

26. COMMITMENTS AND CONTINGENCIES

As at December 31, 2021, unconditional minimum purchase obligations were as follows.

(\$ millions)	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Waneta Expansion capacity agreement ⁽¹⁾	2,525	53	54	55	56	58	2,249
Gas and fuel purchase obligations ⁽²⁾	2,464	787	446	252	169	121	689
Renewable PPAs ⁽³⁾	1,918	122	122	122	122	122	1,308
Power purchase obligations ⁽⁴⁾	1,783	288	254	194	184	185	678
ITC easement agreement ⁽⁵⁾	366	13	13	13	13	13	301
Debt collection agreement ⁽⁶⁾	109	3	3	3	3	3	94
Renewable energy credit purchase agreements ⁽⁷⁾	87	17	16	11	8	6	29
Other ⁽⁸⁾	158	66	7	7	6	4	68
	9,410	1,349	915	657	561	512	5,416

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

⁽²⁾ **FortisBC Energy (\$1,686 million)**: includes contracts for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2021. The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

UNS Energy (\$670 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2021. 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⁾ TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2051, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. Amounts are the estimated future payments.

⁽⁴⁾ **Maritime Electric (\$815 million)**: includes an energy purchase agreement and transmission capacity contract for 30MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario (\$544 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 (\$276 million): includes an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

UNS Energy (\$118 million): an agreement with Salt River Project Agricultural Improvement and Power District to purchase up to 300 MW of capacity, power and ancillary services through 2023. TEP will pay monthly capacity charges and variable power charges.

⁽⁵⁾ ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

⁽⁶⁾ Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, are collected in customer rates.

⁽⁷⁾ UNS Energy and Central Hudson are party to 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 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.

The Wataynikaneyap Partnership has loan agreements in place to finance the project during construction. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of \$235 million.

Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

26. COMMITMENTS AND CONTINGENCIES (cont'd)

Development projects at ITC may result in payments to developers that are contingent on the projects reaching certain milestones indicating that the projects are financially viable. It is reasonably possible that ITC will be required to make these contingent development payments up to a maximum amount of \$88 million upon financial close of the projects. In the event it becomes probable that these payments will be made, the liability and the corresponding intangible asset would be recognized.

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, 2021, 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 \$83 million, for which it has issued a parental guarantee. As at December 31, 2021, there was no obligation under this guarantee.

As at December 31, 2021, 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.