

Consolidated Financial Statements

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2024 and 2023

Consolidated Financial Statements

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2024, 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, 2024, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2024 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, 2024. Deloitte LLP issued an unqualified opinion for both audits.

February 13, 2025

/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, 2024 and 2023, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, 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, 2024, 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 13, 2025, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

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

Critical Audit Matter Description

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

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

How the Critical Audit Matter Was Addressed in the Audit

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

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the terminal growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the terminal growth rate by:
 - Assessing the methodology used in management's determination of the terminal growth rate; and
 - Comparing management's assumptions to historical data and available market projection data.
- 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

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

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, 2024, 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, 2024, 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, 2024, of the Corporation and our report dated February 13, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

	2024	2023
ASSETS		
Current assets		
Cash and cash equivalents	\$ 220	\$ 625
Accounts receivable and other current assets (Note 6)	1,886	1,818
Prepaid expenses	182	150
Inventories (Note 7)	685	566
Regulatory assets (Note 8)	823	866
Total current assets	3,796	4,025
Other assets (Note 9)	1,653	1,298
Regulatory assets (Note 8)	3,808	3,518
Property, plant and equipment, net (Note 10)	49,456	43,385
Intangible assets, net (Note 11)	1,661	1,510
Goodwill (Note 12)	13,112	12,184
Total assets	\$ 73,486	\$ 65,920
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	\$ 98	\$ 119
Accounts payable and other current liabilities (Note 13)	3,353	2,972
Regulatory liabilities (Note 8)	595	577
Current installments of long-term debt (Note 14)	1,990	2,296
Total current liabilities	6,036	5,964
Regulatory liabilities (Note 8)	3,696	3,381
Deferred income taxes (Note 23)	5,020	4,399
Long-term debt (Note 14)	31,224	27,235
Finance leases (Note 15)	343	339
Other liabilities (Note 16)	1,314	1,270
Total liabilities	47,633	42,588
Commitments and contingencies (Note 27)		
Equity		
Common shares ⁽¹⁾	15,589	15,108
Preference shares (Note 18)	1,623	1,623
Additional paid-in capital	8	9
Accumulated other comprehensive income (Note 19)	2,067	653
Retained earnings	4,521	4,112
Shareholders' equity	23,808	21,505
Non-controlling interests	2,045	1,827
Total equity	25,853	23,332
Total liabilities and equity	\$ 73,486	\$ 65,920

⁽¹⁾ No par value. Unlimited authorized shares. 499.3 million and 490.6 million issued and outstanding as at December 31, 2024 and 2023, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel
Jo Mark Zurel,
Director

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

See accompanying Notes to Consolidated Financial Statements

Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

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

	2024	2023
Revenue (Note 5)	\$ 11,508	\$ 11,517
Expenses		
Energy supply costs	3,249	3,771
Operating expenses	3,040	2,889
Depreciation and amortization	1,927	1,773
Total expenses	8,216	8,433
Operating income	3,292	3,084
Other income, net (Note 22)	288	291
Finance charges	1,406	1,305
Earnings before income tax expense	2,174	2,070
Income tax expense (Note 23)	346	360
Net earnings	\$ 1,828	\$ 1,710
Net earnings attributable to:		
Non-controlling interests	\$ 148	\$ 137
Preference equity shareholders (Note 18)	74	67
Common equity shareholders	1,606	1,506
	\$ 1,828	\$ 1,710
Earnings per common share (Note 17)		
Basic	\$ 3.24	\$ 3.10
Diluted	\$ 3.24	\$ 3.10

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

	2024	2023
Net earnings	\$ 1,828	\$ 1,710
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of \$14 million and \$(3) million, respectively	1,561	(402)
Other, net of income tax expense of \$3 million and \$4 million, respectively	9	6
	1,570	(396)
Comprehensive income	\$ 3,398	\$ 1,314
Comprehensive income attributable to:		
Non-controlling interests	\$ 304	\$ 96
Preference equity shareholders	74	67
Common equity shareholders	3,020	1,151
	\$ 3,398	\$ 1,314

See accompanying Notes to Consolidated Financial Statements

Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

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

	2024	2023
Operating activities		
Net earnings	\$ 1,828	\$ 1,710
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	1,695	1,542
Amortization - intangible assets	153	150
Amortization - other	79	81
Deferred income tax expense (Note 23)	154	272
Equity component, allowance for funds used during construction (Note 22)	(139)	(101)
Other	43	72
Change in long-term regulatory assets and liabilities	(99)	(100)
Change in working capital (Note 25)	168	(81)
Cash from operating activities	3,882	3,545
Investing activities		
Additions to property, plant and equipment	(5,012)	(3,986)
Additions to intangible assets	(206)	(183)
Contributions in aid of construction	106	216
Proceeds on disposition, net (Note 21)	—	454
Contributions to equity-accounted investees	—	(24)
Other	(283)	(219)
Cash used in investing activities	(5,395)	(3,742)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	3,124	2,810
Repayments of long-term debt and finance leases	(1,718)	(1,210)
Borrowings under committed credit facilities	8,618	7,217
Repayments under committed credit facilities	(8,055)	(7,276)
Net change in short-term borrowings	(25)	(126)
Issue of common shares, net of costs, and dividends reinvested	46	43
Dividends		
Common shares, net of dividends reinvested	(744)	(701)
Preference shares	(74)	(67)
Subsidiary dividends paid to non-controlling interests	(110)	(83)
Other	2	6
Cash from financing activities	1,064	613
Effect of exchange rate changes on cash and cash equivalents	44	—
Change in cash and cash equivalents	(405)	416
Cash and cash equivalents, beginning of year	625	209
Cash and cash equivalents, end of year	\$ 220	\$ 625

Supplementary Cash Flow Information (Note 25)

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, 2023	490.6	\$ 15,108	\$ 1,623	\$ 9	\$ 653	\$ 4,112	\$ 1,827	\$ 23,332
Net earnings	—	—	—	—	—	1,680	148	1,828
Other comprehensive income	—	—	—	—	1,414	—	156	1,570
Common shares issued	8.7	481	—	—	—	—	—	481
Advances from non-controlling interests	—	—	—	—	—	—	21	21
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(110)	(110)
Dividends declared on common shares (\$2.41 per share)	—	—	—	—	—	(1,197)	—	(1,197)
Dividends on preference shares	—	—	—	—	—	(74)	—	(74)
Other	—	—	—	(1)	—	—	3	2
As at December 31, 2024	499.3	\$ 15,589	\$ 1,623	\$ 8	\$ 2,067	\$ 4,521	\$ 2,045	\$ 25,853
As at December 31, 2022	482.2	\$ 14,656	\$ 1,623	\$ 10	\$ 1,008	\$ 3,733	\$ 1,812	\$ 22,842
Net earnings	—	—	—	—	—	1,573	137	1,710
Other comprehensive loss	—	—	—	—	(355)	—	(41)	(396)
Common shares issued	8.4	452	—	—	—	—	—	452
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(83)	(83)
Dividends declared on common shares (\$2.31 per share)	—	—	—	—	—	(1,127)	—	(1,127)
Dividends on preference shares	—	—	—	—	—	(67)	—	(67)
Other	—	—	—	(1)	—	—	2	1
As at December 31, 2023	490.6	\$ 15,108	\$ 1,623	\$ 9	\$ 653	\$ 4,112	\$ 1,827	\$ 23,332

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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, Oklahoma and Wisconsin.

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

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,442 megawatts ("MW"), including 68 MW of solar capacity and 250 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in northern and southern Arizona.

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 43 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services. FortisBC Energy sources 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. FortisAlberta 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 Power"); 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 145 MW, of which 98 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-island generating capacity of 90 MW. FortisOntario consists of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 3 MW. Wataynikaneyap Power is a transmission company majority-owned by 24 First Nations in which Fortis owns a 39% interest. The 1,800 kilometer Wataynikaneyap Power Transmission Line will connect 17 remote First Nations to the Ontario power grid.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 166 MW. FortisTCL consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a generating capacity of 99 MW, including 95 MW of diesel-powered generating capacity and 4 MW of solar capacity. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

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. Consists of non-regulated holding company expenses, as well as non-regulated long-term contracted generation assets in Belize. The generation assets include three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Fortis Belize Limited, the output of which is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Also includes results for the Aitken Creek natural gas storage facility ("Aitken Creek") until the November 1, 2023 date of disposition (Note 21).

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

2. REGULATION

General

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

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

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

Nature of Regulation		Allowed Common Equity (%)	Allowed ROE ⁽¹⁾ (%)		Significant Features
Regulated Utility	Regulatory Authority		2024	2023	
ITC	Federal Energy Regulatory Commission ("FERC")	60.0	10.73 ⁽²⁾	10.77 ⁽²⁾	Cost-based formula rates, with annual true-up mechanism ⁽³⁾ Incentive adders
TEP	Arizona Corporation Commission ("ACC")	54.3	9.55	9.55 ⁽⁴⁾	COS regulation Historical test year
	FERC	⁽⁵⁾	9.79	9.79	Formula transmission rates
UNS Electric	ACC	53.7	9.75 ⁽⁶⁾	9.50	
UNS Gas	ACC	50.8	9.75 ⁽⁷⁾	9.75	
Central Hudson	New York State Public Service Commission ("PSC")	48.0	9.50 ⁽⁸⁾	9.00	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	45.0	9.65	9.65	COS regulation with formula components and incentives
FortisBC Electric	BCUC	41.0	9.65	9.65	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	9.28	8.50	PBR, with formula to calculate ROE on an annual basis ⁽⁹⁾
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	8.50	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	9.35	9.35	COS regulation Future test year
FortisOntario ⁽¹⁰⁾	Ontario Energy Board	40.0	8.52-9.30	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities ⁽¹¹⁾	Utility Regulation and Competition Office	N/A	8.25-10.25	7.50-9.50	COS regulation Rate-cap adjustment mechanism
FortisTCI ⁽¹²⁾	Government of the Turks and Caicos Islands	N/A	15.00-17.50	15.00-17.50	COS regulation Historical test year

⁽¹⁾ ROA for Caribbean Utilities and FortisTCI

⁽²⁾ Reflects the allowed common equity and ROE for ITC transmission, METC, and ITC Midwest. The ROE above is inclusive of the base ROE as well as incentive adders totalling 0.75%. FERC issued an order in October 2024 retroactively revising the base ROE to certain prior periods including 2023. See "Significant Regulatory Matters" below

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

⁽⁴⁾ Allowed common equity of 54.3% and ROE of 9.55% effective September 1, 2023

⁽⁵⁾ The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio

⁽⁶⁾ Allowed common equity of 53.7% and ROE of 9.75% effective February 1, 2024

⁽⁷⁾ A general rate application requesting new customer rates is ongoing. See "Significant Regulatory Matters" below

⁽⁸⁾ ROE of 9.5% effective July 1, 2024. A general rate application requesting new customer rates effective July 1, 2025 is ongoing. See "Significant Regulatory Matters" below

⁽⁹⁾ In 2023, FortisAlberta was subject to a COS revenue requirement. The ROE for 2025 has been set at 8.97%

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

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

⁽¹²⁾ Operates under 25 and 50 year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037, respectively

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

2. REGULATION (cont'd)

Significant Regulatory Matters

ITC

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

In October 2024, FERC issued an order that removed the use of the risk premium model from the calculation of the base ROE, while maintaining other modifications to the methodology. The updated methodology revised the base ROE from 10.02% to 9.98%, with a maximum ROE inclusive of incentives not to exceed 12.58%. The order also directed the payment of certain refunds, with interest, by December 2025, for the 15-month period from November 2013 through February 2015, and prospectively from September 2016. A regulatory liability of \$39 million (US\$27 million) associated with the refunds has been recognized by ITC as of December 31, 2024.

Certain MISO transmission owners, including ITC, filed a request for rehearing with FERC in November 2024, and filed an appeal of the order with the D.C. Circuit Court in January 2025. The requests for rehearing and appeal primarily focus on the refund period and the related interest. The timing and outcome of these filings are unknown.

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

Transmission Right of First Refusal ("ROFR"): In December 2023, the Iowa District Court ruled that the manner in which Iowa's ROFR statute was passed was unconstitutional. The statute granted incumbent electric transmission owners, including ITC, a ROFR to construct, own and maintain certain electric transmission assets in the state. The District Court did not make any determination on the merits of the ROFR itself, but did issue a permanent injunction preventing ITC and others from taking further action to construct the MISO long-range transmission plan ("LRTP") tranche 1 Iowa projects in reliance on the ROFR.

In May 2024, MISO commenced a variance analysis process as a result of the inability to construct a portion of the tranche 1 LRTP projects in Iowa due to the injunction imposed by the District Court. In August 2024, MISO concluded the variance analysis, which reaffirmed the original allocation of projects to ITC and other incumbent transmission owners. While the results of MISO's variance analysis process allow ITC to move forward with the development of its portion of tranche 1 LRTP projects in Iowa, various legal proceedings with respect to this matter are ongoing for which the timing and outcome are unknown.

UNS Energy

Generic Regulatory Lag Docket: In December 2024, the ACC approved a formula rate plan policy statement which allows utilities to propose formula rates in future rate cases. A formula rate plan, if approved by the ACC, would adjust rates annually based on a predetermined formula. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters.

UNS Gas General Rate Application: In November 2024, UNS Gas filed a general rate application with the ACC requesting an increase in gas delivery rates effective February 1, 2026. The application includes a request to set its ROE at 10.25% and a 56% common equity component of capital structure. In January 2025, UNS Gas filed supplemental material proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement discussed above. The timing and outcome of this proceeding are unknown.

Central Hudson

2025 General Rate Application: In August 2024, Central Hudson filed a general rate application with the PSC requesting an increase in electric and gas delivery rates effective July 1, 2025. The application includes a request to set Central Hudson's allowed ROE at 10% and a 48% common equity component of capital structure. The timing and outcome of this proceeding are unknown.

Show Cause Order: In October 2024, the PSC issued a Show Cause Order which directed Central Hudson to explain why the PSC should not initiate an enforcement proceeding in connection with a gas-related explosion that occurred in November 2023. Central Hudson filed its response in November 2024. The timing and outcome of the Show Cause Order are unknown.

FortisBC Energy and FortisBC Electric

2025-2027 Rate Framework: In April 2024, FortisBC filed an application with the BCUC requesting approval of a rate framework for the period 2025 through 2027. The rate framework builds upon the current multi-year rate plan and includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustaining and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, and the continued sharing with customers of variances from the allowed ROE. The rate framework also proposes the continuation of deferral mechanisms currently in place. A decision from the BCUC is expected in mid-2025.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

2. REGULATION (cont'd)

FortisAlberta

Generic Cost of Capital ("GCOC") Decision: In October 2023, the AUC issued a decision on the 2024 GCOC proceeding. In November 2023, FortisAlberta sought permission to appeal the GCOC decision to the Court of Appeal of Alberta ("Court of Appeal") on the basis that the AUC erred in its decision to not adjust FortisAlberta's ROE and common equity component of capital structure to address incremental business risk associated with competition from Rural Electrification Associations ("REAs") located in FortisAlberta's service area, as well as heightened regulatory risk due to the non-recovery of costs attributable to REAs. In April 2024, the Court of Appeal granted FortisAlberta permission to appeal, and a decision is expected in the first quarter of 2025.

Third PBR Term Decision: In October 2023, the AUC issued a decision establishing the parameters for the third PBR setting term for the period of 2024 through 2028. In November 2023, FortisAlberta sought permission to appeal the decision to the Court of Appeal on the basis that the AUC erred in its decision to determine capital funding using 2018-2022 historical capital investments without consideration for funding of new capital programs included in the company's 2023 cost of service revenue requirement as approved by the AUC. FortisAlberta's application for permission to appeal the decision was heard by the Court of Appeal in December 2024 and a decision is expected in the first quarter of 2025.

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.

Cash and Cash Equivalents

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

Allowance for Credit Losses

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

Inventories

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

Regulatory Assets and Liabilities

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

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

Investments

Investments are reviewed annually for potential impairment in value. Impairments are recognized when identified.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

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 2024 totalled \$74 million (2023 - \$56 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 22). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

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

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

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators and ranged from 0.5% to 33.0% for 2024 (2023 - 0.5% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2024 (2023 - 2.6%).

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

(years)	2024		2023	
	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	5-80	32	5-80	31
Gas	18-83	37	18-95	38
Transmission				
Electric	20-85	42	20-90	41
Gas	10-80	35	10-85	36
Generation	2-95	22	2-95	23
Other	3-80	13	3-80	10

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 2024 (2023 - 1.0% to 33.0%).

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

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

(years)	2024		2023	
	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	3-18	5	3-18	5
Land, transmission and water rights	30-85	52	30-90	52
Other	10-100	16	10-100	14

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

Impairment of Long-Lived Assets

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

Goodwill

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

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

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

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 ("DBP") 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 DBP 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.

DBP 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 DBP 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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

For most of the Corporation's regulated utilities, any difference between DBP or OPEB plan costs ordinarily recognized under U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates. In addition, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with DBP or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8).

Leases

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

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

Revenue Recognition

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

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the Alberta Electric System Operator ("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.

Stock-Based Compensation

Fortis recognizes liabilities associated with directors' deferred share units ("DSUs"), performance share units ("PSUs") and restricted share units ("RSUs"). DSUs represent cash-settled awards whereas PSUs and RSUs represent cash or share-settled awards. 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 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 PSUs and RSUs is over the lesser of three years or the period to retirement eligibility and for DSUs is at the time of grant. Forfeitures are accounted for as they occur.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

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, 2024 was US\$1.00=CA\$1.44 (2023 – US\$1.00=CA\$1.32).

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\$1.37 for 2024 (2023 - US\$1.00=CA\$1.35).

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

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

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; and (ii) UNS Energy, to meet forecast load and reserve requirements. Aitken Creek, to its date of disposition, utilized derivatives to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions (Note 21). 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 Central Hudson 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 Fortis Belize are not subject to income tax.

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

Income Taxes (cont'd)

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 \$8.1 billion as at December 31, 2024 (2023 - \$6.3 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

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

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

Asset Retirement Obligations

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

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

Contingencies

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

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

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.

New Accounting Policies

Segment Reporting: The Corporation adopted ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, for the year ended December 31, 2024 and will adopt it for interim periods beginning in 2025. This update requires disclosure of incremental segment information, including significant segment expenses and other items that are included in segment profit or loss. This adoption of this standard did not materially impact Fortis' disclosures.

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.

Income Taxes: ASU No. 2023-09, *Improvements to Income Tax Disclosures*, is effective for Fortis on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. Fortis does not expect the ASU to materially impact its disclosures.

Expense Disaggregation: ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, is effective for Fortis on January 1, 2027 for annual periods and on January 1, 2028 for interim periods, on a prospective basis, with retrospective application and early adoption permitted. The ASU requires detailed disclosure of certain expense categories included on the consolidated statements of earnings, including energy supply costs, operating expenses, and depreciation and amortization expense. Fortis is assessing the impact on its disclosures.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

4. SEGMENTED INFORMATION

Fortis' CEO is considered the chief operating decision maker ("CODM") for purposes of reviewing segment performance. Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by the CODM in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders, and this measure is used consistently in the evaluation of actual segment performance as well as in the Corporation's business plan and forecasting processes.

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 2024 or 2023.

As of December 31, 2024, accounts receivable included \$18 million due from Belize Electricity (December 31, 2023 - \$8 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2024 and 2023, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2024 and 2023.

(\$ millions)	Regulated							Non-Regulated	Inter-	Total	
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Sub-total	Corporate and Other		segment eliminations
Year ended December 31, 2024											
Revenue	2,229	3,007	1,372	1,665	817	545	1,838	11,473	35	—	11,508
Energy supply costs	—	1,183	393	423	—	155	1,095	3,249	—	—	3,249
Operating expenses	530	798	659	418	195	141	250	2,991	49	—	3,040
Depreciation and amortization	448	404	134	337	291	88	218	1,920	7	—	1,927
Operating income	1,251	622	186	487	331	161	275	3,313	(21)	—	3,292
Other income, net	96	51	58	45	11	6	29	296	(8)	—	288
Finance charges	483	155	79	155	135	81	93	1,181	225	—	1,406
Income tax expense	200	70	37	83	26	14	23	453	(107)	—	346
Net earnings	664	448	128	294	181	72	188	1,975	(147)	—	1,828
Non-controlling interests	122	—	—	1	—	—	25	148	—	—	148
Preference share dividends	—	—	—	—	—	—	—	—	74	—	74
Net earnings attributable to common equity shareholders	542	448	128	293	181	72	163	1,827	(221)	—	1,606
Additions to property, plant and equipment and intangible assets	1,456	1,151	431	1,035	554	132	454	5,213	5	—	5,218
As at December 31, 2024											
Goodwill	8,828	1,987	649	913	231	235	269	13,112	—	—	13,112
Total assets	27,202	14,690	6,278	10,156	6,181	2,807	5,810	73,124	374	(12)	73,486
Year ended December 31, 2023											
Revenue	2,085	3,006	1,360	1,955	738	528	1,761	11,433	84	—	11,517
Energy supply costs	—	1,290	499	760	—	153	1,069	3,771	—	—	3,771
Operating expenses	494	776	601	408	180	127	231	2,817	72	—	2,889
Depreciation and amortization	416	361	113	309	265	96	204	1,764	9	—	1,773
Operating income	1,175	579	147	478	293	152	257	3,081	3	—	3,084
Other income, net	82	49	54	34	6	4	23	252	39	—	291
Finance charges	427	145	67	163	125	79	86	1,092	213	—	1,305
Income tax expense	208	83	29	74	12	9	26	441	(81)	—	360
Net earnings	622	400	105	275	162	68	168	1,800	(90)	—	1,710
Non-controlling interests	114	—	—	1	—	—	22	137	—	—	137
Preference share dividends	—	—	—	—	—	—	—	—	67	—	67
Net earnings attributable to common equity shareholders	508	400	105	274	162	68	146	1,663	(157)	—	1,506
Additions to property, plant and equipment and intangible assets	1,103	916	341	593	608	126	466	4,153	16	—	4,169
As at December 31, 2023											
Goodwill	8,127	1,830	597	913	228	235	254	12,184	—	—	12,184
Total assets	24,269	12,784	5,371	9,225	5,962	2,715	5,227	65,553	401	(34)	65,920

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

5. REVENUE

The following table presents the disaggregation of the Corporation's revenue on the consolidated statements of earnings by geography and substantially autonomous utility operations.

<i>(\$ millions)</i>	2024	2023
Electric and gas revenue		
United States		
ITC	2,205	2,098
UNS Energy	2,731	2,707
Central Hudson	1,366	1,329
Canada		
FortisBC Energy	1,538	1,766
FortisAlberta	770	699
FortisBC Electric	481	460
Newfoundland Power	770	759
Maritime Electric	277	258
FortisOntario	235	217
Caribbean		
Caribbean Utilities	402	388
FortisTCl	118	108
Total electric and gas revenue	10,893	10,789
Other services revenue	350	374
Revenue from contracts with customers	11,243	11,163
Alternative revenue	169	150
Other revenue	96	204
Total revenue	11,508	11,517

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 management fees at UNS Energy for the operation of Springerville Units 3 and 4 and revenue from other services that reflect the ordinary business activities of Fortis' utilities. Other services revenue for 2023 also includes revenue from storage optimization activities at Aitken Creek through the date of disposition (Note 21).

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.

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

Other Revenue

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(\$ millions)	2024	2023
Trade accounts receivable	1,009	890
Unbilled accounts receivable	738	727
Allowance for credit losses	(78)	(68)
	1,669	1,549
Income tax receivable	—	78
Other ⁽¹⁾	217	191
	1,886	1,818

⁽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 26)

Allowance for Credit Losses

The allowance for credit losses changed as follows.

(\$ millions)	2024	2023
Balance, beginning of year	(68)	(58)
Credit loss expensed	(30)	(33)
Credit loss deferral	(31)	(13)
Write-offs, net of recoveries	55	35
Foreign exchange	(4)	1
Balance, end of year	(78)	(68)

See Note 26 for disclosure on the Corporation's credit risk.

7. INVENTORIES

(\$ millions)	2024	2023
Materials and supplies	548	431
Gas and fuel in storage	65	96
Coal inventory	72	39
	685	566

8. REGULATORY ASSETS AND LIABILITIES

(\$ millions)	2024	2023
Regulatory assets		
Deferred income taxes (Note 3)	2,248	2,058
Deferred energy management costs ⁽¹⁾	591	521
Rate stabilization and related accounts ⁽²⁾	453	521
Employee future benefits (Notes 3 and 24)	235	254
Derivatives (Notes 3 and 26)	175	197
Deferred lease costs ⁽³⁾	142	137
Deferred restoration costs ⁽⁴⁾	133	115
Manufactured gas plant site remediation deferral (Note 16)	82	81
Generation early retirement costs ⁽⁵⁾	66	64
Renewable natural gas account ⁽⁶⁾	58	47
Other regulatory assets ⁽⁷⁾	448	389
Total regulatory assets	4,631	4,384
Less: Current portion	(823)	(866)
Long-term regulatory assets	3,808	3,518

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

(\$ millions)	2024	2023
Regulatory liabilities		
Future cost of removal (Note 3)	1,728	1,547
Deferred income taxes (Note 3)	1,329	1,280
Employee future benefits (Notes 3 and 24)	459	294
Rate stabilization and related accounts ⁽²⁾	208	292
Renewable energy surcharge ⁽⁶⁾	155	129
Energy efficiency liability ⁽⁹⁾	88	78
Electric and gas moderator account ⁽¹⁰⁾	61	50
AESO charges deferral ⁽¹¹⁾	58	121
Other regulatory liabilities ⁽⁷⁾	205	167
Total regulatory liabilities	4,291	3,958
Less: Current portion	(595)	(577)
Long-term regulatory liabilities	3,696	3,381

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

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

⁽⁶⁾ **Renewable Natural Gas Account:** Reflects the variance between costs incurred to procure consumable biomethane gas and the related revenue recovered in customer rates. The difference is generally refunded or recovered from customers within one year.

⁽⁷⁾ **Other Regulatory Assets and Liabilities:** Comprised of regulatory assets and liabilities individually less than \$50 million.

⁽⁸⁾ **Renewable Energy Surcharge:** Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through a RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

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

⁽⁹⁾ **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.

⁽¹⁰⁾ **Electric and Gas Moderator Account:** As part of Central Hudson's general rate applications, certain regulatory assets and liabilities were offset and included in the electric and gas moderator account, which will be used for future customer rate moderation.

⁽¹¹⁾ **AESO Charges Deferral:** Relates to differences in revenue collected and amounts incurred for transmission-related items at FortisAlberta that are expected to be collected or refunded in customer rates.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Regulatory assets not earning a return: (i) totalled \$1,908 million and \$1,995 million as at December 31, 2024 and 2023, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

(\$ millions)	2024	2023
Employee future benefits (Note 24)	551	355
Equity investments ⁽¹⁾	259	237
Other investments	225	180
RECs (Note 8)	176	155
Supplemental Executive Retirement Plan ("SERP")	127	117
Operating leases (Note 15)	64	51
Derivatives	48	43
Deferred compensation plan	29	22
Other	174	138
	1,653	1,298

⁽¹⁾ Includes investments in Belize Electricity and Wataynikaneyap Power

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 26).

10. PROPERTY, PLANT AND EQUIPMENT

(\$ millions)	Cost	Accumulated Depreciation	Net Book Value
2024			
Distribution			
Electric	15,771	(4,078)	11,693
Gas	7,148	(1,866)	5,282
Transmission			
Electric	23,084	(4,865)	18,219
Gas	2,937	(894)	2,043
Generation	8,056	(3,110)	4,946
Other	5,014	(1,809)	3,205
Assets under construction	3,578	—	3,578
Land	490	—	490
	66,078	(16,622)	49,456
2023			
Distribution			
Electric	14,352	(3,708)	10,644
Gas	6,682	(1,736)	4,946
Transmission			
Electric	19,886	(4,267)	15,619
Gas	2,751	(843)	1,908
Generation	7,192	(2,739)	4,453
Other	4,444	(1,645)	2,799
Assets under construction	2,581	—	2,581
Land	435	—	435
	58,323	(14,938)	43,385

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")). 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). 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, and information technology assets.

As at December 31, 2024, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy, as well as the Roadrunner Reserve battery storage projects at UNS Energy and the Eagle Mountain Pipeline project at FortisBC Energy.

The cost of PPE under finance lease as at December 31, 2024 was \$324 million (2023 - \$318 million) and related accumulated depreciation was \$119 million (2023 - \$113 million) (Note 15).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2024, interests in jointly owned facilities consisted of the following.

(\$ millions, except as indicated)	Ownership	Cost	Accumulated Depreciation	Net Book Value
	(%)			
Transmission Facilities	Various	1,704	(489)	1,215
Springerville Common Facilities	86.0	580	(344)	236
Springerville Coal Handling Facilities	83.0	299	(154)	145
Four Corners Units 4 and 5 ("Four Corners")	7.0	311	(155)	156
Gila River Common Facilities	50.0	131	(52)	79
Luna Energy Facility ("Luna")	33.3	101	3	104
		3,126	(1,191)	1,935

11. INTANGIBLE ASSETS

(\$ millions)	Cost	Accumulated Amortization	Net Book Value
2024			
Computer software	1,035	(493)	542
Land, transmission and water rights	1,188	(210)	978
Other	143	(95)	48
Assets under construction	93	—	93
	2,459	(798)	1,661
2023			
Computer software	1,040	(528)	512
Land, transmission and water rights	1,071	(182)	889
Other	132	(81)	51
Assets under construction	58	—	58
	2,301	(791)	1,510

Included in the cost of land, transmission and water rights as at December 31, 2024 was \$123 million (2023 - \$113 million) not subject to amortization. Amortization expense was \$153 million for 2024 (2023 - \$150 million). Amortization is estimated to average approximately \$97 million for each of the next five years.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

12. GOODWILL

(\$ millions)	2024	2023
Balance, beginning of year	12,184	12,464
Disposition of Aitken Creek (Note 21)	—	(27)
Foreign currency translation impacts ⁽¹⁾	928	(253)
Balance, end of year	13,112	12,184

⁽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 2024 or 2023.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(\$ millions)	2024	2023
Trade accounts payable	1,121	990
Customer and other deposits	360	263
Dividends payable	314	295
Interest payable	305	274
Accrued taxes other than income taxes	304	268
Employee compensation and benefits payable	303	275
Gas and fuel cost payable	221	232
Derivatives (Note 26)	169	170
Income tax payable	33	—
Employee future benefits (Note 24)	29	28
Other	194	177
	3,353	2,972

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

14. LONG-TERM DEBT

(\$ millions)	Maturity Date	2024	2023
ITC			
Secured U.S. First Mortgage Bonds - 4.34% weighted average fixed rate (2023 - 4.22%)	2027-2055	3,944	3,268
Secured U.S. Senior Notes - 4.16% weighted average fixed rate (2023 - 4.00%)	2028-2055	1,511	1,278
Unsecured U.S. Senior Notes - 4.37% weighted average fixed rate (2023 - 4.16%)	2026-2043	5,610	5,165
Unsecured U.S. Shareholder Note - 6.00% fixed rate (2023 - 6.00%)	2028	286	263
UNS Energy			
Unsecured U.S. Fixed Rate Notes - 4.09% weighted average fixed rate (2023 - 3.80%)	2026-2053	4,172	3,668
Central Hudson			
Unsecured U.S. Promissory Notes - 4.38% weighted average fixed and variable rate (2023 - 4.27%)	2025-2060	1,974	1,687
FortisBC Energy			
Unsecured Debentures - 4.61% weighted average fixed rate (2023 - 4.61%)	2026-2052	3,295	3,295
FortisAlberta			
Unsecured Debentures - 4.63% weighted average fixed rate (2023 - 4.52%)	2034-2054	2,835	2,685
FortisBC Electric			
Unsecured Debentures - 4.72% weighted average fixed rate (2023 - 4.70%)	2035-2054	960	860
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.24% weighted average fixed rate (2023 - 5.24%)	2026-2060	739	748
Secured First Mortgage Bonds - 5.29% weighted average fixed rate (2023 - 5.29%)	2025-2061	320	320
Unsecured Senior Notes - 4.61% weighted average fixed rate (2023 - 4.45%)	2041-2054	207	152
Unsecured U.S. Senior Loan Notes and Bonds - 5.03% weighted average fixed and variable rate (2023 - 4.89%)	2025-2052	876	702
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes - 3.79% weighted average fixed rate (2023 - 3.82%)	2026-2044	2,172	2,251
Unsecured Debentures - 6.51% fixed rate (2023 - 6.51%)	2039	200	200
Unsecured Senior Notes - 4.11% weighted average fixed rate (2023 - 4.10%)	2028-2033	2,000	1,500
Long-term classification of credit facility borrowings		2,216	1,572
Fair value adjustment - ITC acquisition		88	89
Total long-term debt (Note 26)		33,405	29,703
Less: Deferred financing costs and debt discounts		(191)	(172)
Less: Current installments of long-term debt		(1,990)	(2,296)
		31,224	27,235

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

14. LONG-TERM DEBT (cont'd)

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%.

Significant Long-Term Debt Issuances in 2024	Month Issued	Interest Rate (%)	Maturity	Amount (\$ millions)	Use of Proceeds
ITC					
Secured senior notes	January	5.98	2034	US 85	(1) (2) (3)
First mortgage bonds	January	5.11	2029	US 75	(1) (2) (3)
First mortgage bonds	January	5.38	2034	US 75	(1) (2) (3)
Unsecured senior notes	May	5.65	2034	US 400	(3) (4)
First mortgage bonds	December	4.88	2035	US 125	(1) (2) (3)
First mortgage bonds	December	5.25	2043	US 125	(1) (2) (3)
UNS Energy					
Unsecured senior notes	May	5.60	2036	US 30	(1) (3)
Unsecured senior notes	August	5.20	2034	US 400	(3) (4)
Central Hudson					
Senior notes	April	5.59	2031	US 25	(1) (3)
Senior notes	April	5.69	2034	US 35	(1) (3)
Senior notes	October	4.88	2029	US 25	(3) (4)
Senior notes	October	5.30	2034	US 44	(3) (4)
Senior notes	October	5.40	2036	US 35	(3) (4)
FortisBC Electric					
Unsecured debentures	August	4.92	2054	100	(1)
FortisAlberta					
Unsecured debentures	May	4.90	2054	300	(1) (2) (3) (4)
Caribbean Utilities					
Unsecured senior notes	May	6.17	2039	US 40	(1) (2) (3)
Unsecured senior notes	May	6.37	2049	US 40	(1) (2) (3)
FortisOntario					
Unsecured senior notes	August	5.05	2054	55	(1)
Fortis					
Unsecured senior notes	September	4.17	2031	500	(1) (3) (4)

⁽¹⁾ Repay short-term and/or credit facility borrowings

⁽²⁾ Fund capital expenditures

⁽³⁾ General corporate purposes

⁽⁴⁾ Repay maturing long-term debt

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

14. LONG-TERM DEBT (cont'd)

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.

<i>(\$ millions)</i>	Total
2025	1,990
2026	2,585
2027	2,541
2028	1,499
2029	1,024
Thereafter	23,766
	33,405

In December 2024, 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. Fortis also reestablished the at-the-market equity program ("ATM Program") pursuant to the short-form base shelf prospectus, which allows the Corporation to issue up to \$500 million of common shares from treasury to the public from time to time, at the Corporation's discretion, effective until January 10, 2027. As at December 31, 2024, \$500 million remained available under the ATM Program and \$1.5 billion remained available under the short-form base shelf prospectus.

Credit Facilities

<i>(\$ millions)</i>	Regulated Utilities	Corporate and Other	2024	2023
Total credit facilities	4,396	1,946	6,342	6,176
Credit facilities utilized:				
Short-term borrowings ⁽¹⁾	(98)	—	(98)	(119)
Long-term debt (including current portion) ⁽²⁾	(1,335)	(881)	(2,216)	(1,572)
Letters of credit outstanding	(81)	(21)	(102)	(101)
Credit facilities unutilized	2,882	1,044	3,926	4,384

⁽¹⁾ The weighted average interest rate was approximately 6.1% (2023 - 6.9%).

⁽²⁾ The weighted average interest rate was approximately 4.6% (2023 - 6.2%). The current portion was \$1,860 million (2023 - \$1,160 million).

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately \$5.8 billion of the total credit facilities are committed with maturities ranging from 2025 through 2029.

In April 2024, FortisBC Energy increased its operating credit facility from \$700 million to \$900 million and extended the maturity to July 2028. In May 2024, FortisBC Electric increased its operating credit facility from \$150 million to \$200 million and extended the maturity to April 2028.

In May 2024, the Corporation extended the maturity on its unsecured US\$500 million non-revolving term credit facility to May 2025. Half of the term credit facility was repaid in the third quarter of 2024 and the remaining US\$250 million has been fully utilized as at December 31, 2024. The facility is repayable at any time without penalty. In June 2024, the Corporation amended its \$1.3 billion revolving term committed credit facility to extend the maturity to July 2029.

In August 2024, Newfoundland Power increased its operating credit facility from \$100 million to \$130 million and extended the maturity to August 2029.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

14. LONG-TERM DEBT (cont'd)

Consolidated credit facilities of approximately \$6.3 billion as at December 31, 2024 are itemized below.

(\$ millions)	Amount	Maturity
Unsecured committed revolving credit facilities		
Regulated utilities		
ITC ⁽¹⁾	US 1,000	2028
UNS Energy	US 375	2027
Central Hudson	US 250	2029
FortisBC Energy	900	2028
FortisAlberta	250	2029
FortisBC Electric	200	2028
Other Electric	285	(2)
Other Electric	US 83	2025
Corporate and Other	1,350	(3)
Other facilities		
Regulated utilities		
Central Hudson - uncommitted credit facility	US 60	n/a
FortisBC Energy - uncommitted credit facility	55	2025
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 93	2025
Corporate and Other		
Unsecured non-revolving facility	US 250	2025
Unsecured revolving facility	US 150	2025
Unsecured non-revolving facility	21	n/a

⁽¹⁾ ITC also has a US\$400 million commercial paper program, under which \$nil was outstanding as at December 31, 2024 and 2023

⁽²⁾ \$90 million in 2027, \$65 million in 2027, and \$130 million in 2029

⁽³⁾ \$50 million in 2026 and \$1.3 billion in 2029

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 23 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 31 years.

Leases were presented on the consolidated balance sheets as follows.

(\$ millions)	2024	2023
Operating leases		
Other assets	64	51
Accounts payable and other current liabilities	(17)	(12)
Other liabilities	(47)	(39)
Finance leases ⁽¹⁾		
Regulatory assets	142	137
PPE, net	205	205
Accounts payable and other current liabilities	(4)	(3)
Finance leases	(343)	(339)

⁽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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

15. LEASES (cont'd)

The components of lease expense were as follows.

(\$ millions)	2024	2023
Operating lease cost	19	12
Finance lease cost:		
Amortization	2	3
Interest	33	33
Variable lease cost	21	23
Total lease cost	75	71

As at December 31, 2024, the present value of minimum lease payments was as follows.

(\$ millions)	Operating Leases	Finance Leases	Total
2025	18	37	55
2026	15	37	52
2027	12	37	49
2028	6	37	43
2029	4	37	41
Thereafter	19	954	973
	74	1,139	1,213
Less: Imputed interest	(10)	(792)	(802)
Total lease obligations	64	347	411
Less: Current installments	(17)	(4)	(21)
	47	343	390

Supplemental lease information follows.

(\$ millions, except as indicated)	2024	2023
Weighted average remaining lease term (years)		
Operating leases	7	7
Finance leases	31	32
Weighted average discount rate (%)		
Operating leases	4.6	4.5
Finance leases	5.0	5.0

16. OTHER LIABILITIES

(\$ millions)	2024	2023
Employee future benefits (Note 24)	446	527
AROs (Note 3)	249	163
Customer and other deposits	128	168
Stock-based compensation plans (Note 20)	113	82
Manufactured gas plant site remediation ⁽¹⁾	101	94
Derivatives (Note 26)	66	48
Deferred compensation plan (Note 9)	63	54
Operating leases (Note 15)	47	39
Mine reclamation obligations ⁽²⁾	40	30
Retail energy contract ⁽³⁾	20	27
Other	41	38
	1,314	1,270

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

16. OTHER LIABILITIES (Cont'd)

- ⁽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. 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 \$49 million. The present value of the estimated future liability is included in other liabilities.
- ⁽³⁾ FortisAlberta has an agreement with a retail energy provider 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 eight year agreement.

17. EARNINGS PER COMMON SHARE

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

	2024			2023		
	Net Earnings to Common Shareholders (\$ millions)	Weighted Average Shares (# millions)	EPS (\$)	Net Earnings to Common Shareholders (\$ millions)	Weighted Average Shares (# millions)	EPS (\$)
Basic EPS	1,606	495.0	3.24	1,506	486.3	3.10
Potential dilutive effect of stock options (Note 20)	—	0.2	—	—	0.2	—
Diluted EPS	1,606	495.2	3.24	1,506	486.5	3.10

18. PREFERENCE SHARES

Authorized

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

Issued and Outstanding First Preference Shares	2024		2023	
	Number of Shares (thousands)	Amount (\$ millions)	Number of Shares (thousands)	Amount (\$ millions)
Series F	5,000	122	5,000	122
Series G	9,200	225	9,200	225
Series H	7,665	188	7,665	188
Series I	2,335	57	2,335	57
Series J	8,000	196	8,000	196
Series K	10,000	244	10,000	244
Series M	24,000	591	24,000	591
	66,200	1,623	66,200	1,623

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

18. PREFERENCE SHARES (Cont'd)

Characteristics of the first preference shares are as follows:

First Preference Shares ^{(1) (2)}	Dividend Rate (%)	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	6.12	1.5308	2.13	September 1, 2028	25.00	—
Series H	1.84	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	5.47	1.3673	2.05	March 1, 2029	25.00	Series L
Series M	5.49	1.3733	2.48	December 1, 2029	25.00	Series N
Floating rate reset ^{(4) (5)}						
Series I	⁽⁵⁾	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	Series M

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

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

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

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

⁽⁵⁾ The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

<i>(\$ millions)</i>	Opening Balance	Net Change	Ending Balance
2024			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	1,059	1,653	2,712
Hedges of net investments in foreign operations	(452)	(262)	(714)
Income tax recovery	4	14	18
	611	1,405	2,016
Other			
Interest rate hedges (Note 26)	62	10	72
Unrealized employee future benefits (losses) gains (Note 24)	(9)	2	(7)
Income tax expense	(11)	(3)	(14)
	42	9	51
Accumulated other comprehensive income	653	1,414	2,067
2023			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	1,495	(436)	1,059
Hedges of net investments in foreign operations	(530)	78	(452)
Income tax recovery (expense)	7	(3)	4
	972	(361)	611
Other			
Interest rate hedges (Note 26)	49	13	62
Unrealized employee future benefits losses (Note 24)	(6)	(3)	(9)
Income tax expense	(7)	(4)	(11)
	36	6	42
Accumulated other comprehensive income	1,008	(355)	653

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Beginning January 1, 2022, the Corporation no longer grants stock options. Existing options to purchase common shares of the Corporation are exercisable for a period of 10 years from the grant date, expire no later than three years after the death or retirement of the optionee, and vest evenly over a four year period on each anniversary of the grant date. Compensation expense related to stock options was measured at the grant date using the Black-Scholes fair value option-pricing model with each grant amortized to compensation expense evenly over the four year vesting period, with the offsetting entry to additional paid-in capital. Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

As at December 31, 2024, the Corporation had 1.5 million stock options outstanding (2023 - 1.9 million) with a weighted average exercise price of \$48.96 (2023 - \$48.12). There were 1.4 million options vested as of December 31, 2024 (2023 - 1.6 million) with a weighted average exercise price of \$48.87 (2023 - \$47.19).

In 2024, 0.4 million stock options were exercised (2023 - 0.3 million) for cash proceeds of \$15 million (2023 - \$13 million) and an intrinsic value realized by option holders of \$5 million (2023 - \$6 million).

DSUs

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can also 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.

Beginning in 2024, in any year in which a director satisfies their share ownership target, the director may elect to receive a portion of their equity compensation in cash or common shares, with the remaining portion to be granted as DSUs. Common share elections are satisfied quarterly through purchases on the Toronto Stock Exchange or the New York Stock Exchange.

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

DSUs (cont'd)

The following table summarizes information related to DSUs.

	2024	2023
Number of units (thousands)		
Beginning of year	241	224
Granted	29	40
Notional dividends reinvested	10	10
Paid out	(39)	(33)
End of year	241	241

The accrued liability has been recognized at the respective December 31st VWAP and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2024 or 2023.

PSUs

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, and is entitled to commensurate notional common share dividends. PSUs are generally settled in cash with cash payouts calculated at the end of the three year vesting period as the product of: (i) the number 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%. Effective with the 2024 grant, PSUs granted under the Corporation's Omnibus Equity Plan can be settled in cash or common shares of the Corporation. PSUs settled through common shares will be satisfied by issuing common shares from treasury.

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; (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; and (iii) beginning with the 2022 PSU grant, the Corporation's Scope 1 carbon reduction performance as compared to target established at the time of the grant. In addition, the 2023 PSU grant included a payout modifier based on the achievement of diversity, equity and inclusion goals.

The following table summarizes information related to PSUs.

	2024	2023
Number of units (thousands)		
Beginning of year	1,942	1,790
Granted	788	722
Notional dividends reinvested	78	66
Paid out	(609)	(606)
Cancelled/forfeited	(28)	(30)
End of year	2,171	1,942
Additional information (\$ millions)		
Compensation expense recognized	53	45
Compensation expense unrecognized ⁽¹⁾	34	28
Cash payout	44	46
Accrued liability as at December 31 ⁽²⁾	105	90
Aggregate intrinsic value as at December 31 ⁽³⁾	139	118

⁽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, 2024 and 2023

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

RSUs

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, 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 common shares of the Corporation. Beginning with the 2024 grant, RSUs settled through common shares will be satisfied by issuing common shares from treasury.

The following table summarizes information related to RSUs.

	2024	2023
Number of units (thousands)		
Beginning of year	1,079	977
Granted	464	416
Notional dividends reinvested	38	35
Paid out	(357)	(323)
Cancelled/forfeited	(23)	(26)
End of year	1,201	1,079
Additional information (\$ millions)		
Compensation expense recognized	29	21
Compensation expense unrecognized ⁽¹⁾	21	17
Cash payout	19	17
Accrued liability as at December 31 ⁽²⁾	54	42
Aggregate intrinsic value as at December 31 ⁽³⁾	75	59

⁽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

Share-settlements were not material for 2024 and 2023.

21. DISPOSITION

On November 1, 2023, FortisBC Holdings Inc. ("FHI") completed the sale of its Aitken Creek business to a subsidiary of Enbridge Inc. for approximately \$470 million including working capital and closing adjustments, following the satisfaction of all regulatory requirements. The transaction reflected a March 31, 2023 effective date. A gain on disposition of \$23 million (\$10 million after tax), net of transaction costs, was recognized in the Corporate and Other segment.

For the seven-month period between the March 31, 2023 effective date and the November 1, 2023 disposition date, Aitken Creek recognized net earnings, excluding the gain as noted above, of \$5 million.

From January 1, 2023 through to the November 1, 2023 disposition date, excluding the gain, Aitken Creek recognized net earnings of \$20 million.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

22. OTHER INCOME, NET

(\$ millions)	2024	2023
Equity component of AFUDC	139	101
Non-service component of net periodic benefit cost	73	62
Interest income ⁽¹⁾	64	76
Equity income	14	14
Gain on disposal of Aitken Creek, pre-tax (Note 21)	—	23
Gain on derivatives, net	—	9
Net foreign exchange (loss) gain	(10)	4
Other	8	2
	288	291

⁽¹⁾ Includes interest on short-term deposits, as well as interest on regulatory deferrals, including the PPFAC at TEP and UNS Electric

23. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

(\$ millions)	2024	2023
Gross deferred income tax assets		
Regulatory liabilities	659	636
Tax loss and credit carryforwards	629	600
Employee future benefits	123	136
Other	216	144
	1,627	1,516
Valuation allowance	(50)	(23)
Net deferred income tax asset	1,577	1,493
Gross deferred income tax liabilities		
PPE	(5,993)	(5,355)
Regulatory assets	(432)	(372)
Intangible assets	(172)	(165)
	(6,597)	(5,892)
Net deferred income tax liability	(5,020)	(4,399)

Income Tax Expense

(\$ millions)	2024	2023
Canadian		
Earnings before income tax expense	518	526
Current income tax	154	71
Deferred income tax	(87)	17
Total Canadian	67	88
Foreign		
Earnings before income tax expense	1,656	1,544
Current income tax	38	17
Deferred income tax	241	255
Total Foreign	279	272
Income tax expense	346	360

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, 2024 and 2023

23. INCOME TAXES (cont'd)

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

<i>(\$ millions, except as indicated)</i>	2024	2023
Earnings before income tax expense	2,174	2,070
Combined Canadian federal and provincial statutory income tax rate (%)	30.0	30.0
Expected federal and provincial taxes at statutory rate	652	621
(Decrease)/Increase resulting from:		
Foreign and other statutory rate differentials	(169)	(166)
Effects of rate-regulated accounting	(97)	(98)
Tax credits	(36)	(14)
Enactment of new tax laws, change in tax rate	2	12
Other	(6)	5
Income tax expense	346	360
Effective tax rate (%)	15.9	17.4

Income Tax Carryforwards⁽¹⁾

<i>(\$ millions)</i>	Expiring Year	2024
Canadian		
Non-capital loss	2028-2044	155
Other tax credits and restricted interest and financing expenses ⁽²⁾	2026-2044	77
		232
Foreign		
Federal and state net operating loss ⁽³⁾	2029-2044	315
Other tax credits	2027-2044	82
		397
Total income tax carryforwards recognized		629

⁽¹⁾ Income tax carryforwards presented on an after-tax basis

⁽²⁾ Indefinite carryforward for restricted interest and financing expenses

⁽³⁾ Indefinite carryforward for Federal net operating losses, and for states that have adopted the Federal provisions, effective for tax years beginning after December 31, 2017

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2020 to 2024 taxation years are still open for audit in Canadian jurisdictions, and its 2020 to 2024 taxation years are still open for audit in United States jurisdictions.

24. EMPLOYEE FUTURE BENEFITS

For DBP 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, 2021 for certain FortisBC Energy and FortisBC Electric plans; December 31, 2022 for the remaining FortisBC Energy and FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2023 for the Corporation; and December 31, 2024 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 DBP 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, 2024 and 2023

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets <i>(weighted average %)</i>	2024 Target Allocation	2024	2023
Equities	46	47	46
Fixed income	46	45	45
Real estate	7	7	8
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
2024				
Equities	773	1,168	—	1,941
Fixed income	268	1,561	—	1,829
Real estate	—	—	300	300
Cash and other	23	26	—	49
	1,064	2,755	300	4,119
2023				
Equities	666	1,059	—	1,725
Fixed income	232	1,447	—	1,679
Real estate	—	—	291	291
Cash and other	34	14	—	48
	932	2,520	291	3,743

⁽¹⁾ See Note 26 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>	2024	2023
Balance, beginning of year	291	282
Return on plan assets	5	(9)
Foreign currency translation	3	(1)
Purchases, sales and settlements	1	19
Balance, end of year	300	291

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status (\$ millions)	DBP Plans		OPEB Plans	
	2024	2023	2024	2023
Change in benefit obligation ⁽¹⁾				
Balance, beginning of year	3,347	3,063	596	582
Service costs	74	62	25	22
Employee contributions	17	17	4	3
Interest costs	161	159	29	30
Benefits paid	(181)	(169)	(35)	(31)
Actuarial (gains) losses	(115)	255	(49)	(1)
Past service credits/plan amendments	(3)	—	—	—
Foreign currency translation	140	(40)	33	(9)
Balance, end of year ⁽²⁾	3,440	3,347	603	596
Change in value of plan assets				
Balance, beginning of year	3,313	3,079	430	389
Actual return on plan assets	249	373	50	61
Benefits paid	(174)	(162)	(31)	(26)
Employee contributions	17	17	4	3
Employer contributions	57	46	14	13
Foreign currency translation	151	(40)	39	(10)
Balance, end of year	3,613	3,313	506	430
Funded status	173	(34)	(97)	(166)
Balance sheet presentation				
Other assets (Note 9)	395	236	156	119
Other current liabilities (Note 13)	(16)	(15)	(13)	(13)
Other liabilities (Note 16)	(206)	(255)	(240)	(272)
	173	(34)	(97)	(166)

⁽¹⁾ Amounts reflect projected benefit obligation for DBP plans and accumulated benefit obligation for OPEB plans.

⁽²⁾ The accumulated benefit obligation, which excludes assumptions about future salary levels, for DBP plans was \$3,144 million as at December 31, 2024 (2023 - \$2,983 million).

For those DBP plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was \$1,668 million compared to plan assets of \$1,460 million (2023 - \$1,940 million and \$1,681 million, respectively).

For those DBP plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was \$195 million compared to plan assets of \$62 million (2023 - \$268 million and \$130 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was \$296 million compared to plan assets of \$44 million (2023 - \$320 million and \$36 million, respectively).

Net Benefit Cost ⁽¹⁾ (\$ millions)	DBP Plans		OPEB Plans	
	2024	2023	2024	2023
Service costs	74	62	25	22
Interest costs	161	159	29	30
Expected return on plan assets	(221)	(202)	(26)	(22)
Amortization of actuarial gains	(1)	(9)	(17)	(19)
Amortization of past service credits/plan amendments	(1)	(1)	(1)	(1)
Regulatory adjustments	(1)	12	2	5
	11	21	12	15

⁽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, 2024 and 2023

24. 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)	DBP Plans		OPEB Plans	
	2024	2023	2024	2023
Unamortized net actuarial losses (gains)	11	12	(11)	(10)
Unamortized past service costs	1	1	6	6
Income tax (recovery) expense	(3)	(3)	1	1
Accumulated other comprehensive income	9	10	(4)	(3)
Net actuarial losses (gains)	46	189	(283)	(215)
Past service credits	(1)	(2)	(2)	(3)
Other regulatory deferrals	12	(11)	4	2
	57	176	(281)	(216)
Regulatory assets (Note 8)	235	254	—	—
Regulatory liabilities (Note 8)	(178)	(78)	(281)	(216)
Net regulatory assets (liabilities)	57	176	(281)	(216)

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

(\$ millions)	DBP Plans		OPEB Plans	
	2024	2023	2024	2023
Current year net actuarial (gains) losses	(1)	4	(1)	1
Past service credits/plan amendments	—	—	—	(1)
Foreign currency translation	—	(1)	—	—
Income tax recovery	—	(1)	—	—
Total recognized in comprehensive income	(1)	2	(1)	—
Current year net actuarial (gains) losses	(142)	78	(72)	(40)
Amortization of actuarial gains	1	9	16	18
Amortization of past service credits	1	2	1	1
Foreign currency translation	(2)	(1)	(12)	2
Regulatory adjustments	23	(5)	2	(5)
Total recognized in regulatory (liabilities) assets	(119)	83	(65)	(24)

Significant Assumptions

(weighted average %)	DBP Plans		OPEB Plans	
	2024	2023	2024	2023
Discount rate as at December 31 ⁽¹⁾	5.25	4.84	5.43	4.94
Expected long-term rate of return on plan assets ⁽²⁾	6.51	6.58	6.05	5.92
Rate of compensation increase	3.52	3.37	—	—
Health care cost trend increase as at December 31 ⁽³⁾	—	—	4.53	4.52

⁽¹⁾ The discount rate used during the year was 4.84% for DBP plans (2023 - 5.36%) and 4.96% for OPEB plans (2023 - 5.39%). 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 2025 health care cost trend rate is 6.51% and is assumed to decrease over the next 10 years to the ultimate health care cost trend rate of 4.53% in 2034 and thereafter.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments

<i>(\$ millions)</i>	DBP Plans	OPEB Plans
2025	\$ 196	\$ 33
2026	201	34
2027	206	34
2028	210	35
2029	218	36
2030-2034	1,155	203

During 2025, the Corporation expects to contribute \$49 million for DBP plans and \$12 million for OPEB plans.

In 2024, the Corporation expensed \$58 million (2023 - \$53 million) related to defined contribution pension plans.

25. SUPPLEMENTARY CASH FLOW INFORMATION

<i>(\$ millions)</i>	2024	2023
Years ended December 31		
Cash paid (received) for		
Interest	1,361	1,255
Income taxes	(17)	129
Change in working capital		
Accounts receivable and other current assets	(2)	142
Prepaid expenses	(21)	(7)
Inventories	(73)	(1)
Regulatory assets - current portion	93	104
Accounts payable and other current liabilities	115	(390)
Regulatory liabilities - current portion	56	71
	168	(81)
Non-cash financing activity		
Common share dividends reinvested	434	408
As at December 31		
Non-cash investing and financing activities		
Accrued capital expenditures	722	516
Contributions in aid of construction	14	15

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

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

Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flow.

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

Energy Contracts Subject to Regulatory Deferral

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

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2024, unrealized losses of \$175 million (2023 - \$197 million) were recognized as regulatory assets and unrealized gains of \$41 million (2023 - \$37 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, which was sold on November 1, 2023 (Note 21), held gas swap contracts to manage exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2024, gains of \$48 million (2023 - losses of \$28 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 and/or share settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of \$134 million and terms up to three years expiring at varying dates through January 2027. 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 2024, unrealized gains of \$12 million (2023 - \$nil) 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 September 2026 and have a combined notional amount of \$608 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 2024, unrealized losses of \$17 million (2023 - unrealized gains of \$10 million) were recognized in other income, net.

Interest Rate Contracts

During 2024, ITC entered into and settled interest rate locks with a combined notional value of US\$300 million. These contracts were used to manage interest rate risk associated with the issuance of US\$400 million unsecured senior notes in May 2024. Realized losses of US\$3 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

ITC also entered into 5-year interest rate swap contracts in 2024 with a combined notional value of US\$135 million. The swaps will be used to manage interest rate risk associated with forecasted debt issuances. Fair value was measured using a discounted cash flow method based on secured overnight financing rates ("SOFR"). Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, and will be reclassified to earnings as a component of interest expense over the life of the debt. Unrealized gains of US\$4 million were recorded in 2024.

In 2025, ITC entered into 5-year interest rate swap contracts with a notional value of US\$95 million to manage interest rate risk associated with forecasted debt issuances, increasing the total notional amount of interest rate swaps outstanding to US\$230 million.

During 2024, the Corporation entered into and settled interest rate locks with a combined notional value of \$250 million. These contract were used to manage interest rate risk associated with the issuance of \$500 million unsecured senior notes in September 2024. Realized losses of \$2 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over seven years.

Cross-Currency Interest Rate Swaps

The Corporation holds cross-currency interest rate swaps, maturing in 2029, to effectively convert its \$500 million, 4.43% unsecured senior notes to US\$391 million, 4.34% debt. The Corporation has designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the foreign net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR. In 2024, unrealized losses of \$29 million (2023 - unrealized gains of \$15 million) were recorded in other comprehensive income.

Notes to Consolidated Financial Statements

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26. 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, 2024				
Assets				
Energy contracts subject to regulatory deferral ⁽²⁾⁽³⁾	—	63	—	63
Energy contracts not subject to regulatory deferral ⁽²⁾	—	7	—	7
Total return swaps and interest rate contracts ⁽²⁾	—	16	—	16
Other investments ⁽⁴⁾	150	—	—	150
	150	86	—	236
Liabilities				
Energy contracts subject to regulatory deferral ⁽³⁾⁽⁵⁾	—	(197)	—	(197)
Energy contracts not subject to regulatory deferral ⁽⁵⁾	—	(2)	—	(2)
Foreign exchange contracts and cross-currency interest rate swaps ⁽⁵⁾	—	(45)	—	(45)
	—	(244)	—	(244)
As at December 31, 2023				
Assets				
Energy contracts subject to regulatory deferral ⁽²⁾⁽³⁾	—	49	—	49
Energy contracts not subject to regulatory deferral ⁽²⁾	—	6	—	6
Foreign exchange contracts ⁽²⁾	—	5	—	5
Other investments ⁽⁴⁾	145	—	—	145
	145	60	—	205
Liabilities				
Energy contracts subject to regulatory deferral ⁽³⁾⁽⁵⁾	—	(209)	—	(209)
Energy contracts not subject to regulatory deferral ⁽⁵⁾	—	(3)	—	(3)
Total return and cross-currency interest rate swaps ⁽⁵⁾	—	(6)	—	(6)
	—	(218)	—	(218)

⁽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⁾ UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. The fair value of these investments is included in cash and cash equivalents and other assets, with gains and losses recognized in other income, net

⁽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 Posted/(Received)	Net Amount
As at December 31, 2024				
Derivative assets	70	(30)	15	55
Derivative liabilities	(199)	30	—	(169)
As at December 31, 2023				
Derivative assets	55	(24)	28	59
Derivative liabilities	(212)	24	(1)	(189)

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

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

Volume of Derivative Activity

As at December 31, 2024, 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.

	2024	2023
Energy contracts subject to regulatory deferral ⁽¹⁾		
Electricity swap contracts (GWh)	774	628
Electricity power purchase contracts (GWh)	430	588
Gas swap contracts (PJ)	236	228
Gas supply contracts (PJ)	105	134
Energy contracts not subject to regulatory deferral ⁽¹⁾		
Wholesale trading contracts (GWh)	1,499	1,310
Gas swap contracts (PJ)	3	3

⁽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. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

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

Central Hudson has seen an increase in accounts receivable since the suspension of collection efforts initially required in response to the COVID-19 pandemic. Central Hudson continues to contact customers regarding past-due balances and collection efforts continue to expand. Under its regulatory framework, Central Hudson can defer uncollectible write-offs above the amounts collected in customer rates for future recovery.

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

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was \$117 million as at December 31, 2024 (2023 - \$117 million).

Hedge of Foreign Net Investments

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

As at December 31, 2024, US\$2.2 billion (2023 - US\$2.6 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US\$12.6 billion (2023 - US\$11.5 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, 2024, the carrying value of long-term debt, including the current portion, was \$33.4 billion (2023 - \$29.7 billion) compared to an estimated fair value of \$31.3 billion (2023 - \$27.9 billion).

Notes to Consolidated Financial Statements

For the years ended December 31, 2024 and 2023

27. COMMITMENTS AND CONTINGENCIES

As at December 31, 2024, unconditional minimum purchase obligations were as follows.

(\$ millions)	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Gas and fuel purchase obligations ⁽¹⁾	6,299	763	571	520	465	393	3,587
Renewable PPAs ⁽²⁾	2,628	139	166	182	182	173	1,786
Waneta Expansion capacity agreement ⁽³⁾	2,362	56	58	59	60	61	2,068
Power purchase obligations ⁽⁴⁾	1,335	302	217	131	124	122	439
ITC easement agreement ⁽⁵⁾	370	14	14	14	14	14	300
TEP EPC agreements ⁽⁶⁾	308	307	1	—	—	—	—
Debt collection agreement ⁽⁷⁾	99	3	3	3	3	3	84
Renewable energy credit purchase agreements ⁽⁸⁾	58	18	7	6	6	6	15
Other ⁽⁹⁾	140	32	11	11	12	10	64
	13,599	1,634	1,048	926	866	782	8,343

⁽¹⁾ *FortisBC Energy* (\$5,014 million): includes contracts of \$2,792 million for the purchase of renewable natural gas expiring in 2045 and contracts of \$2,222 million for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. *FortisBC Energy's* gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2024. The renewable gas supply obligations disclosed reflect the contracted price per gigajoule between the Corporation and the suppliers.

UNS Energy (\$1,160 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, 2024. 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 2048.

⁽²⁾ *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. The agreements include purchase commitments that are contingent upon the developers obtaining commercial operation of the generating facilities, which are expected to be placed in service in 2026 and 2027. Amounts are the estimated future payments.

⁽³⁾ *FortisBC Electric* is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

⁽⁴⁾ *Maritime Electric* (\$563 million): includes an energy purchase agreement and transmission capacity contract for 30 MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle *Maritime Electric* to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require *Maritime Electric* to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario (\$374 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 (\$301 million): an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

⁽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⁾ *TEP* has entered into two engineering, procurement and construction ("EPC") agreements associated with the development of energy storage projects. Roadrunner Reserve 1 is expected to be placed in service in 2025, with Roadrunner Reserve 2 to follow in 2026.

⁽⁷⁾ *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.

⁽⁸⁾ *UNS Energy and Central Hudson* are party to REC purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

⁽⁹⁾ Includes AROs and joint-use asset and shared service agreements.

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27. COMMITMENTS AND CONTINGENCIES (cont'd)

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately \$165 million of equity capital to Wataynikaneyap Power, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. Wataynikaneyap Power has construction financing loan agreements in place and it is expected that long-term operating financing will replace the construction financing. 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. Equity of \$137 million has been contributed as of December 31, 2024.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of \$360 million for Four Corners. As at December 31, 2024, there was no obligation under these guarantees.

Contingency

In 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 across reserve lands. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In 2016, the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In 2017, the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.