EMERA INCORPORATED

Consolidated
Financial Statements

December 31, 2024 and 2023

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgments and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and with the standards of the Public Company Accounting Oversight Board. Ernst & Young LLP has full and free access to the Audit Committee.

February 21, 2025

"Scott Balfour"	*"Gregory Blunden"*
President and Chief Executive Officer	Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the Consolidated Balance Sheets as at December 31, 2024 and 2023, and the Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2024 and 2023, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

	Accounting for the effects of rate regulation
Key Audit Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $3.4 billion in regulatory assets and $1.9 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including, but not limited to, property, plant and equipment ("PP&E"), operating revenues and expenses, income taxes, and depreciation expense.

Auditing the impact of rate regulation on the Company’s financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company’s judgments include making an assessment of the probability of recovery of and return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund to customers of gains or amounts previously collected from customers through future rates.

How Our Audit Addressed the Key Audit Matter

We performed audit procedures that included, amongst others, assessing the Company’s evaluation of the probability of future recovery for regulatory assets, PP&E, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries’ filings for any evidence that might contradict the Company’s assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery or refund in future rates based on the regulator’s treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries, gains or amounts previously collected from customers or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company’s calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value (“FV”) measurement of derivative financial instruments

Key Audit Matter

Held-for-trading (“HFT”) derivative assets of $270 million and liabilities of $690 million, disclosed in note 16 to the consolidated financial statements, are measured at FV. The Company recognized $207 million in realized and unrealized gains during the year with respect to HFT derivatives.

Auditing the Company’s valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the FV of the contracts. In determining the FV of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the FV of the HFT derivatives.

How Our Audit Addressed the Key Audit Matter

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company’s valuation models and compared the commodity pricing curves used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company’s pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company’s calculations to develop correlation factors and basis differentials. In addition, we assessed whether the FV hierarchy disclosures in note 17 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the FV of derivatives.

Other information
Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's reports thereon, in the Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements
Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements
Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Tracy Brennan.

/s/ Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 21, 2025

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion on the Consolidated Financial Statements
We have audited the accompanying Consolidated Balance Sheets of Emera Incorporated (the "Company") as of December 31, 2024 and 2023, the related Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2024 and 2023, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2024, in conformity with United States generally accepted accounting principles.

Basis for Opinion
These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated 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 consolidated 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.

Accounting for the effects of rate regulation

Description of the Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $3.4 billion in regulatory assets and $1.9 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including, but not limited to, property, plant and equipment ("PP&E"), operating revenues and expenses, income taxes, and depreciation expense. Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund of gains or amounts previously collected from customers through future rates.
How We Addressed the Matter in Our Audit	We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, PP&E, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery or refund in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries, gains or amounts previously collected from customers or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

FV measurement of derivative financial instruments

Description of the Matter	Held-for-trading ("HFT") derivative assets of $270 million and liabilities of $690 million, disclosed in note 16 to the consolidated financial statements, are measured at FV. The Company recognized $207 million in realized and unrealized gains during the year with respect to HFT derivatives. Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the FV of the contracts. In determining the FV of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the FV of the HFT derivatives.

How We Addressed the Matter in Our Audit	We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the FV hierarchy disclosures in note 17 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the FV of derivatives.

/s/ Ernst & Young LLP
Chartered Professional Accountants

We have served as the Company's auditor since 1998.

Halifax, Canada
February 21, 2025

Emera Incorporated
Consolidated Statements of Income

For the millions of dollars (except per share amounts)	Year ended December 31 **2024**	 2023
Operating revenues		
Regulated electric	**$ 5,872**	$ 5,746
Regulated gas	**1,575**	1,489
Non-regulated	**(247)**	328
Total operating revenues (note 6)	**7,200**	7,563
Operating expenses		
Regulated fuel for generation and purchased power	**1,992**	1,881
Regulated cost of natural gas	**396**	527
Operating, maintenance and general expenses ("OM&G")	**1,918**	1,879
Provincial, state, and municipal taxes	**427**	433
Depreciation and amortization	**1,162**	1,049
Impairment charges (note 23)	**225**	-
Total operating expenses	**6,120**	5,769
Income from operations	**1,080**	1,794
Income from equity investments (note 8)	**99**	146
Other income, net (note 9)	**203**	158
Interest expense, net (note 10)	**973**	925
Income before provision for income taxes	**409**	1,173
Income tax (recovery) expense (note 11)	**(159)**	128
Net income	**568**	1,045
Non-controlling interest in subsidiaries ("NCI")	**1**	1
Preferred stock dividends	**73**	66
Net income attributable to common shareholders	**$ 494**	$ 978
Weighted average shares of common stock outstanding (in millions) (note 13)		
Basic	**289**	274
Diluted	**289**	274
Earnings per common share (note 13)		
Basic	**$ 1.71**	$ 3.57
Diluted	**$ 1.71**	$ 3.57
Dividends per common share declared	**$ 2.8775**	$ 2.7875

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Statements of Comprehensive Income

For the millions of dollars	Year ended December 31 **2024**	 2023
Net income	**$ 568**	$ 1,045
Other comprehensive income (loss) ("OCI"), net of tax		
Foreign currency translation adjustment (1)	**1,027**	(270)
Unrealized (losses) gains on net investment hedges (2)	**(139)**	38
Cash flow hedges – reclassification adjustment for gains included in income	**(2)**	(2)
Unrealized gains on available-for-sale investment	**2**	-
Net change in unrecognized pension and post-retirement benefit obligation (3)	**68**	(39)
OCI (4)	**956**	(273)
Comprehensive income	**1,524**	772
Comprehensive income attributable to NCI	**1**	1
Comprehensive Income of Emera Incorporated	**$ 1,523**	$ 771

The accompanying notes are an integral part of these consolidated financial statements.

1) Net of tax expense of $10 million for the year ended December 31, 2024 (2023 – $7 million recovery).

2) The Company has designated $1.2 billion United States dollar (USD) denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations.

3) Net of tax expense of nil for the year ended December 31, 2024 (2023 – $1 million expense).

4) Net of tax expense of $10 million for the year ended December 31, 2024 (2023 – $6 million recovery).

Emera Incorporated
Consolidated Balance Sheets

As at millions of dollars		**December 31** **2024**		December 31 2023
Assets				
Current assets				
Cash and cash equivalents	**$**	**196**	$	567
Restricted cash		**17**		21
Inventory (note 15)		**781**		790
Derivative instruments (notes 16 and 17)		**115**		174
Regulatory assets (note 7)		**595**		339
Receivables and other current assets (note 19)		**1,811**		1,817
Assets held for sale (note 4)		**173**		-
		3,688		3,708
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $10,442 and $9,994, respectively (note 21)		**26,168**		24,376
Other assets				
Deferred income taxes (note 11)		**392**		208
Derivative instruments (notes 16 and 17)		**51**		66
Regulatory assets (note 7)		**2,832**		2,766
Net investment in direct finance and sales type leases (note 20)		**610**		621
Investments subject to significant influence (note 8)		**654**		1,402
Goodwill (note 23)		**5,858**		5,871
Other long-term assets (note 33)		**538**		462
Assets held for sale (note 4)		**2,160**		-
		13,095		11,396
Total assets	**$**	**42,951**	$	39,480

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Balance Sheets – Continued

As at millions of dollars		December 31 2024		December 31 2023
Liabilities and Equity				
Current liabilities				
Short-term debt (note 24)	**$**	**1,400**	$	1,433
Current portion of long-term debt (note 26)		**234**		676
Accounts payable		**1,992**		1,454
Derivative instruments (notes 16 and 17)		**526**		386
Regulatory liabilities (note 7)		**262**		168
Other current liabilities (note 25)		**489**		427
Liabilities associated with assets held for sale (note 4)		**212**		-
		5,115		4,544
Long-term liabilities				
Long-term debt (note 26)		**18,173**		17,689
Deferred income taxes (note 11)		**2,331**		2,352
Derivative instruments (notes 16 and 17)		**91**		118
Regulatory liabilities (note 7)		**1,618**		1,604
Pension and post-retirement liabilities (note 22)		**274**		265
Other long-term liabilities (note 8 and 27)		**910**		820
Liabilities associated with assets held for sale (note 4)		**1,148**		-
		24,545		22,848
Equity				
Common stock (note 12)		**9,042**		8,462
Cumulative preferred stock (note 29)		**1,422**		1,422
Contributed surplus		**84**		82
Accumulated other comprehensive income ("AOCI') (note 14)		**1,261**		305
Retained earnings		**1,468**		1,803
Total Emera Incorporated equity		**13,277**		12,074
NCI (note 30)		**14**		14
Total equity		**13,291**		12,088
Total liabilities and equity	**$**	**42,951**	$	39,480

Commitments and contingencies (note 28)

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors

"Karen Sheriff" *"Scott Balfour"*

Chair of the Board **President and Chief Executive Officer**

Emera Incorporated
Consolidated Statements of Cash Flows

For the		Year ended December 31		
millions of dollars		**2024**		2023
Operating activities				
Net income	**$**	**568**	$	1,045
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization		**1,165**		1,060
Income from equity investments, net of dividends		**(8)**		(22)
Allowance for funds used during construction ("AFUDC") – equity		**(53)**		(38)
Deferred income taxes, net		**(191)**		97
Net change in pension and post-retirement liabilities		**(46)**		(68)
NSPI fuel adjustment mechanism ("FAM")		**451**		(88)
Net change in fair value ("FV") of derivative instruments		**228**		(666)
Net change in regulatory assets and liabilities		**(226)**		554
Net change in capitalized transportation capacity		**175**		434
Goodwill impairment charge		**214**		-
Gain on sale of LIL, excluding transaction costs		**(191)**		-
Other operating activities, net		**108**		28
Changes in non-cash working capital (note 31)		**452**		(95)
Net cash provided by operating activities		**2,646**		2,241
Investing activities				
Additions to PP&E		**(3,151)**		(2,937)
Proceeds from disposal of investment subject to significant influence		**927**		-
Other investing activities		**6**		20
Net cash used in investing activities		**(2,218)**		(2,917)
Financing activities				
Change in short-term debt, net		**56**		(66)
Proceeds from short-term debt with maturities greater than 90 days		**-**		548
Repayment of short-term debt with maturities greater than 90 days		**-**		(1,086)
Proceeds from long-term debt, net of issuance costs		**1,361**		1,932
Retirement of long-term debt		**(1,086)**		(151)
Net repayments under committed credit facilities		**(825)**		(96)
Issuance of common stock, net of issuance costs		**284**		424
Dividends on common stock		**(538)**		(488)
Dividends on preferred stock		**(73)**		(66)
Other financing activities		**3**		(12)
Net cash (used in) provided by financing activities		**(818)**		939
Effect of exchange rate changes on cash, cash equivalents, restricted cash and cash associated with assets held for sale		**23**		(7)
Net (decrease) increase in cash, cash equivalents, restricted cash and cash associated with assets held for sale		**(367)**		256
Cash, cash equivalents, and restricted cash, beginning of year		**588**		332
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, end of year	**$**	**221**	$	588
Cash, cash equivalents, restricted cash and cash associated with assets held for sale consists of:				
Cash	**$**	**191**	$	559
Short-term investments		**5**		8
Restricted cash		**17**		21
Assets held for sale		**8**		-
Cash, cash equivalents, restricted cash and cash associated with assets held for sale	**$**	**221**	$	588

Supplementary Information to Consolidated Statements of Cash Flows (note 31)

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Statements of Changes in Equity

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	NCI	Total Equity
Balance, December 31, 2023	**$ 8,462**	**$ 1,422**	**$ 82**	**$ 305**	**$ 1,803**	**$ 14**	**$ 12,088**
Net income of Emera Inc.	**-**	**-**	**-**	**-**	**567**	**1**	**568**
Other comprehensive income, net of tax expense of $10 million	**-**	**-**	**-**	**956**	**-**	**-**	**956**
Dividends declared on preferred stock (note 29)	**-**	**-**	**-**	**-**	**(73)**	**-**	**(73)**
Dividends declared on common stock ($2.8775/share)	**-**	**-**	**-**	**-**	**(829)**	**-**	**(829)**
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	**261**	**-**	**-**	**-**	**-**	**-**	**261**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	**291**	**-**	**-**	**-**	**-**	**-**	**291**
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	**28**	**-**	**2**	**-**	**-**	**-**	**30**
Other	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Balance, December 31, 2024	**$ 9,042**	**$ 1,422**	**$ 84**	**$ 1,261**	**$ 1,468**	**$ 14**	**$ 13,291**
Balance, December 31, 2022	$ 7,762	$ 1,422	$ 81	$ 578	$ 1,584	$ 14	$ 11,441
Net income of Emera Inc.	-	-	-	-	1,044	1	1,045
Other comprehensive loss, net of tax recovery of $6 million	-	-	-	(273)	-	-	(273)
Dividends declared on preferred stock (note 29)	-	-	-	-	(66)	-	(66)
Dividends declared on common stock ($2.7875/share)	-	-	-	-	(759)	-	(759)
Issued under the ATM, net of after-tax issuance costs	397	-	-	-	-	-	397
Issued under the DRIP, net of discount	272	-	-	-	-	-	272
Senior management stock options exercised and ECSPP	31	-	1	-	-	-	32
Other	-	-	-	-	-	(1)	(1)
Balance, December 31, 2023	$ 8,462	$ 1,422	$ 82	$ 305	$ 1,803	$ 14	$ 12,088

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Notes to the Consolidated Financial Statements
As at December 31, 2024 and 2023

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Emera Incorporated ("Emera" or the "Company") is an energy and services company that invests in electricity generation, transmission and distribution, and gas transmission and distribution.

At December 31, 2024, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 855,000 customers in West Central Florida;

- Canadian Electric Utilities, which includes:
  - Nova Scotia Power Inc. ("NSPI"), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 557,000 customers; and
  - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion, including AFUDC, transmission project between the island of Newfoundland and Nova Scotia.

  On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect minority equity interest in the Labrador Island Link Partnership ("LIL"), which was previously included in the Canadian Electric Utilities segment. For further details, refer to note 4.

- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 508,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 550,000 customers in New Mexico. On August 5, 2024, Emera announced an agreement to sell NMGC. The transaction is expected to close in late 2025, subject to certain approvals, including approval by the New Mexico Public Regulation Commission ("NMPRC"). For further details, refer to note 4.
  - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States ("US") border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy Canada"), which expires in 2034;
  - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
  - a 12.9 per cent equity interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline that transports natural gas throughout markets in Atlantic Canada and the northeastern US.

- Other Electric Utilities, which includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
  - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated regulated electric utility on the island of Barbados, serving approximately 135,000 customers;
  - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,500 customers; and
  - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

- Emera's other segment includes investments in energy-related non-regulated companies that are below the required threshold for reporting as separate segments and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments. This includes:
    - Emera Energy, which consists of:
        - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
        - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
        - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
    - Emera US Finance LP ("Emera Finance"), EUSHI Finance, Inc. and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
    - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the US; and
    - Other investments.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP") and, in the opinion of management, include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera.

All dollar amounts are presented in Canadian dollars ("CAD"), unless otherwise indicated.

Principles of Consolidation

These consolidated financial statements include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for VIEs in which Emera is not the primary beneficiary.

The Company performs ongoing analysis to assess whether it holds any VIEs or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method. For further details on VIEs, refer to note 33.

Intercompany balances and transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues. An offset is recorded to PP&E, regulatory assets, regulated fuel for generation and purchased power, or OM&G, depending on the nature of the transaction.

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. Rates are designed to recover prudently incurred costs of providing regulated products or services and provide an opportunity for a reasonable rate of return on invested capital, as applicable. For further detail, refer to note 7.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to CAD at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Assets and liabilities of foreign operations whose functional currency is not the Canadian dollar are translated using exchange rates in effect at the balance sheet date and the results of operations at the average exchange rate in effect for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCI.

The Company designates certain USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date, is recorded in OCI.

Revenue Recognition

Regulated Electric and Gas Revenue:
Electric and gas revenues, including energy charges, demand charges, basic facilities charges and clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity and gas are delivered to customers over time as the customer simultaneously receives and consumes the benefits. Electric and gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity and gas are recognized at rates approved by the respective regulators and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, electricity and gas delivered to customers, but not billed, is estimated and corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the megawatt hours ("MWh") or therms delivered to customers at the established rates expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

Non-regulated Revenue:
Marketing and trading margins are comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management revenues. Revenues are recorded when obligations under terms of the contract are satisfied and are presented on a net basis reflecting the nature of contractual relationships with customers and suppliers.

Energy sales are recognized when obligations under the terms of the contracts are satisfied, which is when electricity is delivered to customers over time.

Other non-regulated revenues are recorded when obligations under the terms of the contract are satisfied.

Other:
Sales, value add, and other taxes, except for gross receipts taxes discussed below, collected by the Company concurrent with revenue-producing activities are excluded from revenue.

Franchise Fees and Gross Receipts

TEC and PGS recover from customers certain costs incurred, on a dollar-for-dollar basis, through prices approved by the Florida Public Service Commission ("FPSC"). The amounts included in customers' bills for franchise fees and gross receipt taxes are included as "Regulated electric" and "Regulated gas" revenues in the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by TEC and PGS are included as an expense on the Consolidated Statements of Income in "Provincial, state and municipal taxes".

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statements of Income.

PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units, are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E are replaced, renewed or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income. Where a disposition of non-regulated PP&E occurs, gains and losses are included in income as the dispositions occur.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO, and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and labour costs, along with other costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have a future economic benefit.

Normal maintenance projects and major maintenance projects that do not increase overall life of the related assets are expensed as incurred. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. For some of Emera's rate-regulated subsidiaries, depreciation is calculated using the group remaining life method, which is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property. The service lives of regulated assets require regulatory approval.

Intangible assets, which are included in “PP&E” on the Consolidated Balance Sheets, consist primarily of computer software and land rights. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the asset in each category. For some of Emera’s rate-regulated subsidiaries, amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets. The service lives of regulated intangible assets require regulatory approval.

Goodwill

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV of identifiable assets acquired and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment and is adjusted for the impact of foreign exchange (“FX”). Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

If the Company performs a qualitative assessment and determines it is more likely than not that its FV is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the FV of the reporting unit to its carrying value, including goodwill (“carrying amount”). If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management’s best estimate of the reporting unit’s projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit’s residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. For the market approach, management estimates FV based on comparable companies and transactions within comparable industries, or in the case of the NMGC quantitative assessment in 2024, transactions involving the reporting unit. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit’s net operating loss (“NOL”) and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera’s reporting units.

As of December 31, 2024, Emera’s goodwill represented the excess of the acquisition purchase price for TECO Energy, Inc. (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q3 2024, Emera entered into an agreement to sell NMGC. As a result, a quantitative goodwill impairment assessment was performed on the NMGC reporting unit and the Company recorded a goodwill impairment charge of $210 million ($198 million, after-tax) or $155 million USD ($146 million USD, after-tax). The reduced NMGC goodwill balance of $303 million is included in the NMGC disposal unit classified as held for sale. For further details, refer to note 23.

In Q4 2024, a qualitative assessment was performed for TEC given the significant excess of FV over carrying amounts calculated during the last quantitative test in Q4 2023. Management concluded it was more likely than not that the FV of this reporting unit exceeded its carrying amount, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the PGS reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2024 using a combination of the income and market approach. This assessment estimated that the FV of the PGS reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

Income Taxes and Investment Tax Credits

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets, and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. 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 is enacted, unless required to be offset to a regulatory asset or liability by law or by order of the regulator. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred income tax assets will be recovered from future taxable income is assessed and assumptions are made about the expected timing of reversal of deferred income tax assets and liabilities. If management subsequently determines it is likely that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded to reflect the amount of deferred income tax asset expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned on regulated assets by TEC, PGS and NMGC are deferred and amortized as required by regulatory practices.

TEC, PGS, NMGC and BLPC collect income taxes from customers based on current and deferred income taxes. NSPI, NSPML and Brunswick Pipeline collect income taxes from customers based on income tax that is currently payable, except for the deferred income taxes on certain regulatory balances specifically prescribed by regulators. For the balance of regulated deferred income taxes, NSPI, NSPML and Brunswick Pipeline recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets. GBPC is not subject to income taxes.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. For further detail, refer to note 11.

Derivatives and Hedging Activities

The Company manages its exposure to normal operating and market risks relating to commodity prices, FX, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of FX forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. These physical and financial contracts are classified as HFT. Collectively, these contracts and financial instruments are considered derivatives.

The Company recognizes the FV of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. Physical contracts that meet the NPNS exception are not recognized on the balance sheet; these contracts are recognized in income when they settle. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption if the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. The change in FV of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. Management believes any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates. TEC and PGS have no derivatives related to hedging.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of non-regulated operating revenues, fuel for generation and purchased power, other expenses, inventory, and OM&G, depending on the nature of the item being economically hedged. Transportation capacity arising as a result of marketing and trading derivative transactions is recognized as an asset in “Receivables and other current assets” and amortized over the period of the transportation contract term. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the FV amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables and other current assets” and obligations to return cash collateral are recognized in “Accounts payable”.

Leases

The Company determines whether a contract contains a lease at inception by evaluating whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Emera has leases with independent power producers (“IPP”) and other utilities for annual requirements to purchase wind and hydro energy over varying contract lengths which are classified as finance leases. These finance leases are not recorded on the Company’s Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as “Regulated fuel for generation and purchased power” on the Consolidated Statements of Income.

Operating lease liabilities and right-of-use assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera’s leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as “OM&G” on the Consolidated Statements of Income.

Where the Company is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that consists of the sum of the minimum lease payments and residual value, net of estimated executory costs and unearned income. The difference between the gross investment and the cost of the leased item is recorded as unearned income at the inception of the lease. Unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

For sales-type leases, the accounting is similar to the accounting for direct finance leases however, the difference between the FV and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

Emera has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition.

Receivables and Allowance for Credit Losses

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date. The Company recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

Inventory

Fuel and materials inventories are valued at the lower of weighted-average cost or net realizable value, unless evidence indicates the weighted-average cost will be recovered in future customer rates.

Asset Impairment

Long-Lived Assets:
Emera assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or sale of a business.

The assessment involves comparing undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated FV. The Company’s assumptions relating to future results of operations or other recoverable amounts, are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company’s expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which consider external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

In 2024, impairment charges of $19 million ($14 million after-tax) were recognized on certain assets, $8 million of which was included in Other income, net with $11 million included in Impairment charges on the Consolidated Income Statement. No impairment charges related to long-lived assets were recognized in 2023.

Equity Method Investments:
The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's FV. No impairment of equity method investments was required in either 2024 or 2023.

Financial Assets:
Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required in either 2024 or 2023.

Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the FV of estimated cash flows necessary to discharge the future obligation, using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives, and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. AROs are included in "Other long-term liabilities" and accretion expense is included as part of "Depreciation and amortization". Any regulated accretion expense not yet approved by the regulator is recorded in "PP&E" and included in the next depreciation study.

Some of the Company's transmission and distribution assets may have conditional AROs that are not recognized in the consolidated financial statements, as the FV of these obligations could not be reasonably estimated, given insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at FV in the period in which an amount can be determined.

Cost of Removal ("COR")

TEC, PGS, NMGC and NSPI recognize non-ARO COR as regulatory liabilities or regulatory assets. The non-ARO COR represent funds received from customers through depreciation rates to cover estimated future non-legally required COR of PP&E upon retirement. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Stock-Based Compensation

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit (“DSU”) plan; a performance share unit (“PSU”) plan; and a restricted share unit (“RSU”) plan. The Company accounts for its plans in accordance with the FV-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated FV of the award, and is recognized as an expense over the employee’s or director’s requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are initially measured at FV and re-measured at FV at each reporting date, with the change in liability recognized in income.

Employee Benefits

The costs of the Company’s pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes unamortized gains and losses and past service costs in “AOCI” or “Regulatory assets” on the Consolidated Balance Sheets. The components of net periodic benefit cost other than the service cost component are included in “Other income, net” on the Consolidated Statements of Income. For further detail, refer to note 22.

Government Grants

The Company accounts for government grants by applying a grant accounting model by analogy to International Accounting Standards (“IAS”) 20, Accounting for Government Grants and Disclosure of Government Assistance. A grant relating to an asset is reflected in the determination of the carrying amount of the asset. A grant relating to income is presented as a deduction from the related expense it is intended to compensate.

In 2024, the Company received an aggregate of $47 million (2023 – $7 million) of government grants from various Canadian and US government agencies towards capital projects included in PP&E. The capital projects receiving grants primarily relate to the Company’s decarbonization and environmental compliance initiatives. Further details on significant grant programs utilized in 2024 and 2023 are noted below.

Natural Resources Canada (“NRCan”) Smart Renewables & Electrification Pathways (“SREP”):
On March 27, 2024, NSPI was approved for a grant under the NRCan SREPs to fund the construction of three 50 MW battery storage systems in Nova Scotia. NSPI can make claims under the grant for 33 per cent of eligible project costs to a maximum $109 million. Eligible costs can be incurred until March 31, 2027. For the year-end December 31, 2024, NSPI received $26 million (2023 – nil) in funding under the grant, which has been recorded as a reduction to the carrying amount of the project in PP&E.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policy that is applicable to, and adopted by the Company in 2024, is described as follows:

Improvements to Reportable Segment Disclosures

The Company adopted Accounting Standard Update (“ASU”) 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance was effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Adoption of the standard resulted in additional qualitative disclosures provided in note 5.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB, but as allowed, have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, Income Statement Reporting–Comprehensive Income–Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard update improves the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation and amortization) included within income statement expense captions. The guidance will be effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The standard updates are to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements disclosures.

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements disclosures.

4. DISPOSITIONS

Pending Sale of NMGC

On August 5, 2024, Emera entered into an agreement to sell its indirect wholly owned subsidiary NMGC for a total enterprise value of approximately $1.3 billion USD, consisting of cash proceeds and the transfer of debt and customary closing adjustments. The transaction is expected to close in late 2025, subject to certain approvals, including approval by the NMPRC. As a result of the pending sale, NMGC's assets and liabilities are classified as held for sale.

As the transaction proceeds will be lower than the carrying amount of the assets and liabilities being sold, Emera assessed the NMGC reporting unit for goodwill impairment by comparing the FV of expected transaction proceeds to the carrying value of net assets, including goodwill of $366 million USD ("NMGC carrying amount"). The goodwill of the reporting unit was determined to be impaired and a non-cash goodwill impairment charge of $210 million ($198 million, after-tax) or $155 million USD ($146 million USD, after-tax) was recorded in "Impairment Charges" on the Consolidated Statements of Income in Q3 2024.

Following the goodwill impairment assessment, the held for sale assets and liabilities were measured at the lower of their carrying amount or fair value less costs to sell. The measurement resulted in an additional loss for the estimated future transaction costs of $16 million ($12 million after-tax), in addition to incurred transaction costs of $9 million ($7 million after-tax) recorded in “Other Income, net” on the Consolidated Statements of Income in Q3 2024.

The Company will continue to record depreciation on the NMGC assets through the transaction closing date, as the depreciation continues to be reflected in customer rates and will be reflected in the carryover basis of the assets when sold. Depreciation and amortization of $26 million ($19 million USD) was recorded on these assets from August 5, 2024, the date they were classified as held for sale, through December 31, 2024.

Details of the assets and liabilities classified as held for sale are as follows:

As at millions of dollars	December 31 2024
Cash and cash equivalents	$ 8
Inventory	9
Derivative instruments	1
Regulatory assets	28
Receivables and other current assets	127
Current assets held for sale	**$ 173**
PP&E	1,828
Regulatory assets	6
Goodwill	303
Other long-term assets	23
Long-term assets held for sale	**$ 2,160**
Total assets held for sale	**$ 2,333**
Short-term debt	$ 46
Derivative instruments	1
Regulatory liabilities	10
Accounts payable and other current liabilities	155
Current liabilities associated with assets held for sale	**212**
Long-term debt	696
Deferred income taxes	167
Regulatory liabilities	274
Other long-term liabilities	11
Long-term liabilities associated with assets held for sale	**$ 1,148**
Total liabilities associated with assets held for sale	**$ 1,360**

Sale of LIL Equity Interest

On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect minority equity interest in the LIL for a total transaction value of $1.2 billion, including cash proceeds of $957 million and $235 million for assuming Emera’s contractual obligation to fund the remaining initial capital investment, which represents additional LIL equity interest for the acquirer. Cash proceeds from the sale in the amount of $30 million is held in escrow pending finalization of certain agreements with the LIL general partner. The escrow proceeds receivable is held at FV and included in the gain on sale, after transaction costs. As of December 31, 2024, the estimated FV of the escrow proceeds receivable is $25 million. In Q2 2024, a gain on sale, after transaction costs, of $182 million, ($107 million, after tax and transaction costs), was recognized in “Other Income, net” on the Consolidated Statements of Income and included in the Other segment. In Q4 2024, Emera recognized a $22 million tax benefit due to the reversal of a prior year valuation allowance related to loss carryforwards applied against a portion of the taxable capital gain on the sale of LIL. This tax benefit was recorded in “Income Tax (Recovery) Expense” on the Consolidated Statements of Income in Q4 2024 and included in the Other segment.

5. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part to their different operating, regulatory and geographical environments. Segments are reported based on each subsidiary's contribution of revenues, net income attributable to common shareholders and total assets, as reported to the Company's chief operating decision maker ("CODM"). Emera's CODM is the Chief Executive Officer.

For the Company's reportable segments, the CODM uses several measures to allocate capital and resources for each segment, predominantly in the annual budget and forecasting processes. The CODM evaluates segment performance by considering budget-to-actual variances for these measures monthly. The measure used by the CODM that is the most consistent with USGAAP measurement principles is net income attributable to common shareholders.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2024							
Operating revenues from external customers (1)	$ 3,451	$ 1,855	$ 1,595	$ 566	$ (267)	$ -	$ **7,200**
Inter-segment revenues (1)	9	-	14	-	19	(42)	**-**
Total operating revenues	3,460	1,855	1,609	566	(248)	(42)	**7,200**
Regulated fuel for generation and purchased power	852	859	-	295	-	(14)	**1,992**
Regulated cost of natural gas	-	-	396	-	-	-	**396**
OM&G	779	408	454	143	154	(20)	**1,918**
Provincial, state and municipal taxes	273	48	103	3	-	-	**427**
Depreciation and amortization	622	282	182	69	7	-	**1,162**
Impairment charges	-	-	11	-	214	-	**225**
Income from equity investments	-	73	20	4	2	-	**99**
Other income, net	66	28	16	12	73	8	**203**
Interest expense, net (2)	265	168	151	22	367	-	**973**
Income tax expense (recovery)	94	(41)	89	1	(302)	-	**(159)**
NCI in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	73	-	**73**
Net income (loss) attributable to common shareholders	$ 641	$ 232	$ 259	$ 48	$ (686)	$ -	$ **494**
Capital expenditures	$ 1,942	$ 481	$ 619	$ 81	$ 4	$ -	$ **3,127**
As at December 31, 2024							
Total assets	$ 24,375	$ 7,609	$ 8,439	$ 1,444	$ 1,810	$ (726)	$ **42,951**
Investments subject to significant influence	$ -	$ 475	$ 124	$ 55	$ -	$ -	$ **654**
Goodwill	$ 5,035	$ -	$ 823	$ -	$ -	$ -	$ **5,858**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs of $29 million for the year ended December 31, 2024, between the Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Operating revenues from external customers (1)	$ 3,548	$ 1,671	$ 1,510	$ 526	$ 308	$ -	$ **7,563**
Inter-segment revenues (1)	8	-	14	-	31	(53)	**-**
Total operating revenues	3,556	1,671	1,524	526	339	(53)	**7,563**
Regulated fuel for generation and purchased power	920	699	-	275	-	(13)	**1,881**
Regulated cost of natural gas	-	-	527	-	-	-	**527**
OM&G	830	384	405	130	151	(21)	**1,879**
Provincial, state and municipal taxes	289	45	91	3	5	-	**433**
Depreciation and amortization	571	276	126	68	8	-	**1,049**
Income from equity investments	-	109	21	4	12	-	**146**
Other income, net	69	32	11	7	20	19	**158**
Interest expense, net (2)	271	170	129	23	332	-	**925**
Income tax expense (recovery)	117	(9)	64	-	(44)	-	**128**
NCI in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	66	-	**66**
Net income (loss) attributable to common shareholders	$ 627	$ 247	$ 214	$ 37	$ (147)	$ -	$ **978**
Capital expenditures	$ 1,736	$ 450	$ 664	$ 63	$ 8	$ -	$ **2,921**
As at December 31, 2023							
Total assets	$ 21,119	$ 8,634	$ 7,735	$ 1,311	$ 1,938	$ (1,257)	$ **39,480**
Investments subject to significant influence	$ -	$ 1,236	$ 118	$ 48	$ -	$ -	$ **1,402**
Goodwill	$ 4,628	$ -	$ 1,240	$ -	$ 3	$ -	$ **5,871**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs of $95 million for the year ended December 31, 2023, between the Florida Electric Utility, Gas Utilities and Infrastructure and Other segments.

Geographical Information

Revenues (based on country of origin of the product or service sold)

For the millions of dollars	Year ended December 31 **2024**	 2023
United States	**4,712**	$ 5,310
Canada	**1,922**	1,727
Barbados	**427**	389
The Bahamas	**139**	137
	$ 7,200	$ 7,563

PP&E:

As at millions of dollars	**December 31 2024**	December 31 2023
United States (1)	**$ 20,084**	$ 18,588
Canada	**5,068**	4,878
Barbados	**645**	576
The Bahamas	**371**	334
	$ 26,168	$ 24,376

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale and excluded from the table above. For further details on the pending transaction, refer to note 4.

6. REVENUE

The following disaggregates the Company's revenue by major source:

	Electric			Gas	Other		
millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2024							
Regulated Revenue							
Residential	$ 2,063	$ 997	$ 203	$ 712	$ -	$ -	$ 3,975
Commercial	939	499	300	496	-	-	2,234
Industrial	223	276	28	94	-	(14)	607
Other electric	372	41	7	-	-	-	420
Regulatory deferrals	(157)	-	15	-	-	-	(142)
Other (1)	20	42	13	224	-	(9)	290
Finance income (2)(3)	-	-	-	63	-		63
Regulated revenue	$ 3,460	$ 1,855	$ 566	$ 1,589	$ -	$ (23)	$ 7,447
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	77	-	77
Other non-regulated operating revenue	-	-	-	20	32	(24)	28
Mark-to-market (3)	-	-	-	-	(357)	5	(352)
Non-regulated revenue	$ -	$ -	$ -	$ 20	$ (248)	$ (19)	$ (247)
Total operating revenues	**$ 3,460**	**$ 1,855**	**$ 566**	**$ 1,609**	**$ (248)**	**$ (42)**	**$ 7,200**
For the year ended December 31, 2023							
Regulated Revenue							
Residential	$ 2,307	$ 910	$ 183	$ 724	$ -	$ -	**$** 4,124
Commercial	1,083	463	285	425	-	-	2,256
Industrial	274	219	33	93	-	(13)	606
Other electric	395	41	7	-	-	-	443
Regulatory deferrals	(522)	-	12	-	-	-	(510)
Other (1)	19	38	6	199	-	(8)	254
Finance income (2)(3)	-	-	-	62	-	-	62
Regulated revenue	$ 3,556	$ 1,671	$ 526	$ 1,503	$ -	$ (21)	7,235
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	96	-	96
Other non-regulated operating revenue	-	-	-	21	27	(23)	25
Mark-to-market (3)	-	-	-	-	216	(9)	207
Non-regulated revenue	$ -	$ -	$ -	$ 21	$ 339	$ (32)	328
Total operating revenues	$ 3,556	$ 1,671	$ 526	$ 1,524	$ 339	$ (53)	$ 7,563

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations:

Remaining performance obligations primarily represent gas transportation contracts, lighting contracts, and long-term steam supply arrangements with fixed contract terms. As of December 31, 2024, the aggregate amount of the transaction price allocated to remaining performance obligations was $495 million (2023 – $488 million), including $3 million related to NMGC. This amount includes $135 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040. This amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2044.

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets represent prudently incurred costs that have been deferred because it is probable they will be recovered through future rates or tolls collected from customers. Management believes existing regulatory assets are probable for recovery either because the Company received specific approval from the applicable regulator, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

As at millions of dollars		**December 31 2024 (1)**		December 31 2023
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,227**	$	1,233
TEC capital cost recovery for early retired assets		**737**		671
Storm cost recovery clauses		**613**		52
Pension and post-retirement medical plan		**395**		364
TEC capital cost recovery for retired Polk Unit 1 components		**205**		-
Deferrals related to derivative instruments		**42**		88
Cost recovery clauses		**33**		151
Environmental remediations		**29**		26
Stranded cost recovery		**27**		25
NSPI FAM		**-**		395
Other (2)		**119**		100
	$	**3,427**	$	3,105
Current	**$**	**595**	$	339
Long-term		**2,832**		2,766
Total regulatory assets	**$**	**3,427**	$	3,105
Regulatory liabilities				
Deferred income tax regulatory liabilities		**828**		830
Accumulated reserve – COR		**733**		849
Cost recovery clauses		**121**		32
NSPI FAM		**56**		-
Deferrals related to derivative instruments		**44**		17
BLPC Self-insurance fund ("SIF") (note 33)		**32**		29
Other (2)		**66**		15
	$	**1,880**	$	1,772
Current	**$**	**262**	$	168
Long-term		**1,618**		1,604
Total regulatory liabilities	**$**	**1,880**	$	1,772

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale and excluded from the table above. For further details on the pending transaction, refer to note 4.
(2) Comprised of regulatory assets and liabilities that are not individually significant.

Deferred Income Tax Regulatory Assets and Liabilities

To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, a regulatory asset or liability is recognized as appropriate.

TEC Capital Cost Recovery for Early Retired Assets

Represents the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were early retired. The balance earns a rate of return as permitted by the FPSC and is recovered as a separate line item on customer bills for a period of 15 years, beginning in January 2022.

Storm Cost Recovery Clauses

TEC and PGS Storm Reserve:
The storm reserve is for hurricanes and other named storms that cause significant damage to TEC and PGS systems. As allowed by the FPSC, if charges to the storm reserve exceed the storm reserve liability, the excess is to be carried as a regulatory asset. TEC and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period or longer, as determined by the FPSC, as well as replenish the reserve.

NSPI Storm Rider:
NSPI has a UARB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the ability to apply to the UARB for recovery of costs if major storm restoration expenses exceed approximately $10 million in a given year. The storm rider was effective as of the General Rate Application ("GRA") decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application.

GBPC Storm Restoration:
This asset includes storm restoration costs incurred by GBPC related to Hurricane Dorian in 2020 and Hurricane Matthew in 2016.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at TEC, PGS and, in 2023, NMGC. Deferred costs of postretirement benefits that are included in expense are recognized as cost of service for rate-making purposes as permitted by the FPSC and New Mexico Public Regulation Commission ("NMPRC"), as applicable and amortized over the remaining service life of plan participants.

TEC Capital Cost Recovery for Retired Polk Unit 1 Components

This regulatory asset relates to the remaining net book value of certain components of Polk Unit 1 that were early retired on December 31, 2024. The balance earns a rate of return as permitted by the FPSC and will be recovered through base rates over an 11-year recovery period beginning on January 1, 2025.

Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in FV of derivatives that are documented as economic hedges or that do not qualify for NPNS exemption, as a regulatory asset or liability as approved by the UARB. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, other income, inventory, or OM&G, depending on the nature of the item being economically hedged.

Cost Recovery Clauses

These assets and liabilities are clauses and riders related to TEC, PGS and, in 2023, NMGC. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in a subsequent period.

Environmental Remediations

This asset is primarily related to PGS costs associated with environmental remediation at Manufactured Gas Plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

Stranded Cost Recovery

Due to decommissioning of a GBPC steam turbine in 2012, the GBPA approved recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base and expected to be included in rates in future years.

NSPI FAM

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through regularly scheduled fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

Accumulated Reserve – COR

This regulatory asset or liability represents the non-ARO COR reserve in TEC, PGS, NSPI and in 2023, NMGC. AROs represent the FV of estimated cash flows associated with the Company's legal obligation to retire its PP&E. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E value upon retirement that are not legally required. This reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service.

Regulatory Environments and Updates

Florida Electric Utility

TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which can occur at the initiative of TEC, the FPSC or other interested parties.

TEC's approved regulated return on equity ("ROE") range for 2024 and 2023 was 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent (2023 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

Base Rates:
On April 2, 2024, TEC filed a rate case with the FPSC for new base rates. On December 3, 2024, the FPSC rendered a decision which includes annual base rate increases of $185 million USD in 2025 and adjustments of $87 million USD and $9 million USD in 2026 and 2027, respectively. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital and the allowed regulatory ROE range is 9.50 per cent to 11.50 per cent with a 10.50 per cent midpoint. On February 3, 2025, the FPSC issued the final order approving the decision, effective January 1, 2025. On February 18, 2025, a motion for reconsideration on certain aspects of the rate case order was filed with the FPSC.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

Fuel Recovery and Other Cost Recovery Clauses:
TEC has a fuel recovery clause approved by the FPSC, allowing the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs, including a return on capital invested. Differences between prudently incurred fuel costs and the cost-recovery rates and amounts recovered from customers through electricity rates in a year are deferred to a regulatory asset or liability and recovered from or returned to customers in subsequent periods.

On April 2, 2024, TEC requested a mid-course adjustment to its fuel and capacity charges, reflecting a $138 million USD reduction over 12 months, from June 2024 through May 2025. The requested reduction was due to a decrease in actual and projected 2024 natural gas prices since TEC submitted its projected 2024 costs in the fall of 2023. On May 7, 2024, the FPSC approved the mid-course adjustment.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

Storm Reserve:
On September 26, 2024, Hurricane Helene passed 100 miles west of Tampa and made landfall approximately 200 miles north of Tampa, in Taylor County, as a Category 4 hurricane. TEC’s service territory was impacted by the tropical storm force winds and storm surge which resulted in a peak number of customers out of 100,000. As of December 31, 2024, TEC deferred $49 million USD to the storm reserve for future recovery.

On October 9, 2024, Hurricane Milton made landfall approximately 50 miles south of Tampa, near Sarasota, and was the worst weather event to impact the area in over 100 years. The Category 3 hurricane had a significant impact on TEC’s service territory which resulted in a peak number of customers out of 600,000. As of December 31, 2024, TEC deferred $340 million USD to the storm reserve for future recovery.

As at December 31, 2024, total restoration costs charged to the storm reserve account have exceeded the storm reserve balance, and therefore $377 million USD has been deferred as a regulatory asset for future recovery. On February 4, 2025, the FPSC approved TEC’s petition, filed on December 27, 2024, for the recovery of $466 million USD for costs associated with Hurricane Idalia, Hurricane Debby, Hurricane Helene and Hurricane Milton and the associated interest which will replenish the storm reserve over an 18-month recovery period beginning March 2025. The amount of cost-recovery is subject to a true-up mechanism with the FPSC.

In September 2022, TEC was impacted by Hurricane Ian, with $119 million USD of restoration costs charged against TEC’s FPSC approved storm reserve. On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC’s petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. The remaining balance of $29 million USD as of December 31, 2023, was collected over 12 months in 2024.

Storm Protection Cost Recovery Clause and Settlement Agreement:
The Storm Protection Plan Cost Recovery Clause provides a process for Florida investor-owned utilities, including TEC, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Differences between prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred and recovered from or returned to customers in a subsequent year. The current approved plan addressed the years 2023, 2024 and 2025 and was approved by the FPSC in October, 2022.

Canadian Electric Utilities

NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia ("Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI's approved regulated ROE range for 2024 and 2023 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent of approved rate base.

GRA:
On February 2, 2023, the UARB approved the GRA settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increases of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

Fuel Recovery:
On April 17, 2024, the UARB approved the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the $117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the $117 million from customers on behalf of Invest Nova Scotia over a 10-year period, which began in Q2 2024, and is remitting those amounts to Invest Nova Scotia quarterly.

Federal Loan Guarantee ("FLG"):
On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSPML and the Province of Nova Scotia (the "Province") on terms and conditions for a FLG of $500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On September 25, 2024, NSPI and NSPML filed applications with the UARB related to the FLG. On November 29, 2024, the UARB approved NSPML's application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and to increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance. On February 18, 2025, the UARB approved NSPI's application to increase 2025 fuel rates to service the incremental NSPML debt.

Storm Rider:
On December 2, 2024, the UARB approved the recovery of $24 million of major storm restoration and incremental financing costs deferred to NSPI's storm rider in 2023 to be recovered over a 12-month period beginning on January 1, 2025.

Hurricane Fiona:
On June 27, 2024, the UARB approved the deferred recognition of $25 million in incremental operating costs incurred during the Hurricane Fiona storm restoration efforts in September 2022. Following UARB approval, the $25 million was reclassified to “Regulatory assets” from “Other long-term assets”. The UARB also directed NSPI to reclassify $10 million of undepreciated costs related to assets retired because of Hurricane Fiona to “Regulatory assets” from “PP&E” on the Consolidated Balance Sheets. NSPI began amortizing both of these regulatory assets over a 10-year period beginning July 1, 2024.

Nova Scotia Cap-and-Trade (“Cap-and-Trade”) Program:
On December 31, 2022, the FAM included a cumulative $166 million in fuel costs related to the accrued purchase of emissions credits and $6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Cap-and-Trade Program.

Extra Large Industrial Active Demand Tariff:
On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

NSPML

Equity earnings from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML’s approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

Newfoundland and Labrador Hydro’s (“NLH”) Nova Scotia Block (“NS Block”) delivery obligations commenced in 2021 and delivery will continue over the next 35 years pursuant to the agreements.

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSPML, and the Province on terms and conditions for a FLG of $500 million in debt to be issued by NSPML. For further information, refer to the NSPI section above.

On November 29, 2024, NSPML received approval from the UARB to collect up to $197 million in 2025 from NSPI; which includes $158 million for the recovery of costs associated with the Maritime Link, and $39 million associated with the additional FLG debt and financing costs noted in the NSPI section above. Payments from NSPI are subject to a holdback of up to $4 million per month. There was no holdback recorded for the year ended December 31, 2024.

On December 21, 2023, NSPML received approval from the UARB to collect up to $164 million in 2024 from NSPI for the recovery of costs associated with the Maritime Link subject to a holdback of $4 million per month.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million related to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments". The UARB also confirmed that NSPML can apply for termination of the holdback mechanism upon 90 per cent of NS Block deliveries being achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023.

Gas Utilities and Infrastructure

PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

PGS's approved ROE range for 2024 and 2023 was 9.15 per cent to 11.15 per cent with a 10.15 per cent midpoint, based on an allowed equity capital structure of 54.7 per cent.

Base Rates:
On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

Fuel Recovery:
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its Purchased Gas Adjustment Clause ("PGAC"). This clause is designed to recover actual costs incurred by PGS for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

Recovery of Energy Conservation and Pipeline Replacement Programs:
The FPSC annually approves a conservation charge that is intended to permit PGS to recover prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are required by Florida law and approved and monitored by the FPSC. PGS also has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. In February 2017, the FPSC approved expansion of the Cast Iron/Bare Steel clause to allow recovery of accelerated replacement of certain obsolete plastic pipe. The majority of cast iron and bare steel pipe has been removed from its system, with replacement of obsolete plastic pipe continuing until 2028 under the rider.

NMGC

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to its cost of providing service, plus an appropriate return on invested capital.

NMGC's approved ROE for 2024 and 2023 was 9.375 per cent on an allowed equity capital structure of 52 per cent.

Base Rates:
On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates. On March 1, 2024, NMGC filed with the NMPRC a settlement with the support of all parties in the case for an increase of $30 million USD in annual base revenues and maintaining NMGC's ROE at 9.375 per cent. The rates reflect the recovery of increased operating costs and capital investments in pipeline projects and related infrastructure, as well as a new customer information and billing system. NMGC also agreed to withdraw, and to not reassert in a future rate case application, its request for a regulatory asset for costs associated with its 2022 application for a certificate of public convenience and necessity for a liquefied natural gas storage facility in New Mexico. The NMPRC approved the rate case settlement on July 25, 2024. New rates became effective October 1, 2024.

Fuel Recovery:
NMGC recovers gas supply costs through a PGAC. This clause recovers actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, transmission, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC can adjust charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. NMGC received approval of its PGAC Continuation in December 2024, for the four-year period ending December 2028.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Saint John LNG import terminal near Saint John, New Brunswick to markets in the northeastern US. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy Canada. The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract. The pipeline is considered a Group II pipeline regulated by the Canada Energy Regulator ("CER"). The CER Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the CER Act and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

Other Electric Utilities

BLPC

BLPC is regulated by the Fair Trading Commission ("FTC"), under the Utilities Regulation (Procedural) Rules 2003. BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's approved regulated return on rate base was 10 per cent for 2024 and 2023.

Licenses:
BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

Base Rates:
In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities totalling approximately $71 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC's February 15 and November 20, 2023, decisions to the Supreme Court of Barbados in the High Court of Justice (the "Court") and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC's position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC's final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time. The appeal is currently scheduled to be heard in 2025.

Fuel Recovery:
BLPC's fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The calculation of the fuel charge is adjusted on a monthly basis and reported to the FTC for approval.

Clean Energy Transition Rider ("CETR"):
On May 31, 2023, the FTC approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETR (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETR. On May 6, 2024, the FTC approved the recovery of a 15 MW battery storage system through the CETR.

Barbados Domestic Tax Rate Change:
On May 24, 2024, the Government of Barbados signed the Income Tax (Amendment and Validation) Act into law. The legislation, effective January 1, 2024, implemented a corporate income tax rate of 9 per cent, requiring BLPC to remeasure its deferred income tax liabilities. On July 18, 2024, BLPC requested the deferred recovery of the $5 million USD remeasurement. BLPC is seeking amortization of the costs over a period to be approved by the FTC during a future rate setting process.

GBPC

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's approved regulated return on rate base was 8.52 per cent for 2024 (2023 – 8.32 per cent).

Electricity Act, 2024:
On June 1, 2024, the Electricity Act, 2024 took effect. The legislation purports to remove the jurisdiction of the GBPA over GBPC and to have the Utilities Regulation and Competition Authority, another Bahamian regulator, regulate GBPC.

Base Rates:
There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. On August 1, 2024, as required by the GBPA Operating Protocol and Regulatory Framework Agreement, GBPC filed a rate plan proposal and is awaiting regulatory review.

Fuel Recovery:
GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. In 2023 and 2024, the fuel pass through charge was adjusted monthly, in-line with actual fuel costs.

8. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value As at December 31 **2024**	2023	Equity Income For the year ended December 31 **2024**	2023	Percentage of Ownership **2024**
NSPML	$ **475**	$ 489	$ **44**	$ 46	**100.0**
M&NP (1)	**124**	118	**20**	21	**12.9**
Lucelec (1)	**55**	48	**4**	4	**19.5**
LIL (2)	**-**	747	**29**	63	**-**
Bear Swamp (3)	**-**	-	**2**	12	**50.0**
	$ 654	$ 1,402	**$ 99**	$ 146	

(1) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, records its investment in these entities using the equity method.
(2) On June 4, 2024, Emera completed the sale of its equity interest in the LIL. For further details, refer to note 4.
(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $92 million (2023 – $81 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $9 million difference between the cost and the underlying FV of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 33). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of dollars	December 31 **2024**	December 31 2023
Balance Sheets		
Current assets	**$ 37**	$ 21
PP&E	**1,425**	1,473
Regulatory assets (1)	**778**	272
Non-current assets	**27**	29
Total assets	**$ 2,267**	$ 1,795
Current liabilities	**$ 55**	$ 48
Long-term debt (2)	**1,570**	1,109
Non-current liabilities	**167**	149
Equity	**475**	489
Total liabilities and equity	**$ 2,267**	$ 1,795

(1) On November 29, 2024, the UARB approved the creation of a $500 million regulatory asset for debt issued as a result of the FLG. For further details, refer to note 7.
(2) On December 16, 2024, NSPML issued a $500 million bond under the FLG. For further details refer to note 7.

9. OTHER INCOME, NET

For the millions of dollars	Year ended December 31 **2024**	 2023
Gain on sale of LIL, net of transaction costs (1)	**$ 182**	$ -
AFUDC	**53**	38
Pension non-current service cost recovery	**35**	35
Interest income	**23**	43
Transaction costs related to the pending sale of NMGC (1)	**(25)**	-
Charges related to wind-down costs and certain asset impairments (2)	**(29)**	-
FX (losses) gains	**(58)**	20
Other	**22**	22
	$ 203	$ 158

(1) For more information related to the gain on sale, after transaction costs, of Emera's indirect minority interest in the LIL and the pending sale of NMGC, refer to note 4.
(2) Primarily related to the wind-down of Block Energy LLC

10. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of dollars	Year ended December 31 **2024**	 2023
Interest on debt	**$ 1,004**	$ 954
Allowance for borrowed funds used during construction	**(23)**	(16)
Other	**(8)**	(13)
	$ 973	$ 925

11. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

millions of dollars	**2024**	2023
Income before provision for income taxes	**$ 409**	$ 1,173
Statutory income tax rate	**29.0%**	29.0%
Income taxes, at statutory income tax rate	**119**	340
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(90)**	(72)
Interest and financing expenses	**(58)**	-
Valuation allowance	**(58)**	3
Tax credits	**(57)**	(53)
Goodwill impairment charge	**49**	-
Amortization of deferred income tax regulatory liabilities	**(36)**	(33)
Foreign tax rate variance	**(31)**	(36)
Additional impact from the sale of LIL equity interest	**22**	-
Tax effect of equity earnings	**(14)**	(15)
Manufacturing allowance	**(9)**	(8)
Other	**4**	2
Income tax (recovery) expense	**$ (159)**	$ 128
Effective income tax rate	**(39%)**	11%

Bahamian Domestic Minimum Top-up Tax Act (“Domestic Top-up Tax Act”):
On November 28, 2024, the Domestic Top-up Tax Act was enacted with an effective date of January 1, 2024.The Domestic Top-up Tax Act did not have an impact on the Company.

Excessive Interest and Financing Expenses Limitation ("EIFEL") Regime:
On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the EIFEL regime, which is effective January 1, 2024. EIFEL applies to limit a company's net interest and financing expense deduction to no more than 30 per cent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely.

During 2024, the Company incurred $185 million of interest and financing expenses in connection with a specific financing structure. The interest and financing expenses related to the financing structure as well as $88 million of other interest and financing expenses are expected to be denied under the EIFEL regime. It was determined that the Company is more likely than not to realize the tax benefit of the denied interest and financing expenses in future periods and therefore a $79 million deferred income tax asset has been recorded as at December 31, 2024. In Q4 2024, the Company recognized a $58 million tax benefit related to the denied interest and financing expenses and the reversal of the related deferred income tax liability in connection with the financing structure and its wind-up.

Canadian Global Minimum Tax Act ("GMTA"):
On June 20, 2024, the GMTA was enacted with an effective date of January 1, 2024. The GMTA did not have an impact on the Company.

Barbados Domestic Tax Rate Change:
On May 24, 2024, the Government of Barbados signed the Income Tax (Amendment and Validation) Act into law. The legislation, effective January 1, 2024, implemented a corporate income tax rate of 9 per cent, requiring BLPC to remeasure its deferred income tax liabilities.

Barbados Corporation Top-up Tax (Amendment) Act ("Top-up Tax Act"):
On May 24, 2024, the Top-up Tax Act was enacted with an effective date of January 1, 2024. The Top-up Tax Act did not have an impact on the Company.

United States Inflation Reduction Act ("IRA"):
On August 16, 2022, the IRA was signed into legislation. The IRA includes numerous tax incentives for clean energy, such as the extension and modification of existing investment and production tax credits for projects placed in service through 2024, and introduces new technology-neutral clean energy related tax credits beginning in 2025. As of December 31, 2024, the Company has recorded a $82 million (December 31, 2023 – $30 million) regulatory liability on the Consolidated Balance Sheets in recognition of its obligation to pass the incremental tax benefits realized to customers.

The following table reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of dollars		**2024**		2023
Current income taxes				
Canada	**$**	**29**	$	26
United States		**4**		5
Deferred income taxes				
Canada		**(200)**		93
United States		**155**		128
Adjustments to beginning of the year valuation allowance				
Canada		**(61)**		-
Investment tax credits				
United States		**(6)**		(29)
Operating loss carryforwards				
Canada		**(4)**		(93)
United States		**(76)**		(2)
Income tax (recovery) expense	**$**	**(159)**	$	128

The following table reflects the composition of income before provision for income taxes presented in the Consolidated Statements of Income for the years ended December 31:

millions of dollars	**2024**	2023
Canada	**$ 156**	$ 171
United States	**203**	964
Other	**50**	38
Income before provision for income taxes	**$ 409**	$ 1,173

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of dollars	**2024**	2023
Deferred income tax assets:		
Tax loss carryforwards	**$ 1,118**	$ 1,195
Tax credit carryforwards	**534**	454
Regulatory liabilities	**225**	175
Derivative instruments	**144**	205
Other	**462**	372
Total deferred income tax assets before valuation allowance	**2,483**	2,401
Valuation allowance	**(322)**	(363)
Total deferred income tax assets after valuation allowance	**$ 2,161**	$ 2,038
Deferred income tax liabilities:		
PP&E	**$ (3,421)**	$ (3,223)
Regulatory assets	**(198)**	(196)
Derivative instruments	**(105)**	(235)
Investments subject to significant influence	**(46)**	(216)
Other	**(330)**	(312)
Total deferred income tax liabilities	**$ (4,100)**	$ (4,182)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	**$ 392**	$ 208
Long-term deferred income tax liabilities	**(2,331)**	(2,352)
Net deferred income tax liabilities	**$ (1,939)**	$ (2,144)

Considering all evidence regarding the utilization of the Company’s deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for certain loss carryforwards and unrealized capital losses on long-term debt and investments. A valuation allowance of $322 million has been recorded as at December 31, 2024 (2023 – $363 million) related to the loss carryforwards, long-term debt and investments. During 2024, the Company recognized a $58 million tax benefit primarily due to the utilization of certain loss carryforwards, which were subject to a valuation allowance as at December 31, 2023.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, $4.7 billion as at December 31, 2024 (2023 – $4.7 billion) in cumulative temporary differences for which deferred taxes might otherwise be required, have not been recognized. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera's NOL, capital loss and tax credit carryforwards and their expiration periods as at December 31, 2024 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 2,420	$ (967)	$ 1,453	2026 - 2044
Capital loss	55	(55)	-	Indefinite
Tax Credit	2	(1)	1	2028 - 2042
United States				
Federal NOL	$ 1,587	$ (1)	$ 1,586	2036 - Indefinite
State NOL	1,351	(1)	1,350	2026 - Indefinite
Tax credit	533	(3)	530	2025 - 2044
Other				
NOL	$ 91	$ (23)	$ 68	2025 - 2031

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of dollars	**2024**	2023
Balance, January 1	**$ 37**	$ 33
Increases due to tax positions related to current year	**6**	5
Increases due to tax positions related to a prior year	**2**	1
Decreases due to tax positions related to a prior year	**(3)**	(2)
Balance, December 31	**$ 42**	$ 37

Unrecognized tax benefits relate to the timing of certain tax deductions at NSPI and research and development tax credits primarily at TEC. The total amount of unrecognized tax benefits as at December 31, 2024 was $42 million (2023 – $37 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $10 million (2023 – $9 million) with $1 million interest expense recognized in the Consolidated Statements of Income (2023 – $2 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next 12 months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $126 million (2023 – $126 million), including interest. NSPI has prepaid $55 million (2023 – $55 million) of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

Should NSPI be similarly reassessed by the CRA for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Notice of Appeal process is not determinable at this time.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, and St. Lucia income tax returns. As at December 31, 2024, the Company's tax years still open to examination by taxing authorities include 2006 and subsequent years.

12. COMMON STOCK

Authorized: Unlimited number of non-par value common shares.

	2024		2023	
Issued and outstanding:	**millions of shares**	**millions of dollars**	millions of shares	millions of dollars
Balance, January 1	**284.12**	**$ 8,462**	269.95	$ 7,762
Issuance of common stock under ATM program (1)(2)	**5.12**	**261**	8.29	397
Issued under the DRIP, net of discounts	**6.10**	**291**	5.26	272
Senior management stock options exercised and Employee Share Purchase Plan	**0.60**	**28**	0.62	31
Balance, December 31	**295.94**	**$ 9,042**	284.12	$ 8,462

(1) For the year ended December 31, 2023, a total of 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs).
(2) For the year ended December 31, 2024, a total of 5,117,273 common shares were issued under Emera's ATM program at an average price of $51.52 per share for gross proceeds of $264 million ($261 million net of after-tax issuance costs). As at December 31, 2024, an aggregate gross sales limit of $336 million remained available for issuance under the ATM program.

As at December 31, 2024, the following common shares were reserved for issuance: 6 million (2023 – 6 million) under the senior management stock option plan, 2 million (2023 – 2 million) under the employee common share purchase plan and 12 million (2023 – 18 million) under the DRIP.

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2024, Emera was in compliance with this requirement.

ATM Equity Program

On November 18, 2024, Emera increased the size of the ATM Program to allow the Company to issue up to $1 billion of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was increased by an amendment dated November 18, 2024 to its prospectus supplement dated November 14, 2023 and an amendment dated November 13, 2024 to its short form base shelf prospectus dated October 3, 2023.

13. EARNINGS PER SHARE

Basic earnings per share is determined by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan, convertible debentures and shares issued under the DRIP.

The following table reconciles the computation of basic and diluted earnings per share:

For the millions of dollars (except per share amounts)	Year ended December 31 **2024**	 2023
Numerator		
Net income attributable to common shareholders	**$ 493.6**	$ 977.7
Diluted numerator	**493.6**	977.7
Denominator		
Weighted average shares of common stock outstanding – basic	**289.1**	273.6
Stock-based compensation	**0.1**	0.2
Weighted average shares of common stock outstanding – diluted	**289.2**	273.8
Earnings per common share		
Basic	**$ 1.71**	$ 3.57
Diluted	**$ 1.71**	$ 3.57

14. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI are as follows:

millions of dollars	Unrealized gain (loss) on translation of self-sustaining foreign operations	Net change in net investment hedges	Gains (losses) on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2024						
Balance, January 1, 2024	**$ 369**	**$ (24)**	**$ 14**	**$ (2)**	**$ (52)**	**$ 305**
OCI before reclassifications	**1,027**	**(139)**	**-**	**2**	**-**	**890**
Amounts reclassified from AOCI	**-**	**-**	**(2)**	**-**	**68**	**66**
Net current period OCI	**1,027**	**(139)**	**(2)**	**2**	**68**	**956**
Balance, December 31, 2024	**$ 1,396**	**$ (163)**	**$ 12**	**$ -**	**$ 16**	**$ 1,261**
For the year ended December 31, 2023						
Balance, January 1, 2023	$ 639	$ (62)	$ 16	$ (2)	$ (13)	$ 578
OCI before reclassifications	(270)	38	-	-	-	(232)
Amounts reclassified from AOCI	-	-	(2)	-	(39)	(41)
Net current period OCI	(270)	38	(2)	-	(39)	(273)
Balance, December 31, 2023	$ 369	$ (24)	$ 14	$ (2)	$ (52)	$ 305

The reclassifications out of AOCI are as follows:

For the millions of dollars	Affected line item in the Consolidated Financial Statements	Year ended December 31 **2024**	 2023
Gains on derivatives recognized as cash flow hedges			
Interest rate hedge	Interest expense, net	**$ (2)**	$ (2)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses	Other income, net	**$ 2**	$ -
Past service (gains) costs	Other income, net	**(2)**	2
Amounts reclassified into obligations	Pension and post-retirement benefits	**68**	(40)
Total before tax		**68**	(38)
Income tax expense		**-**	(1)
Total net of tax		**$ 68**	$ (39)
Total reclassifications out of AOCI, net of tax, for the period		**$ 66**	$ (41)

15. INVENTORY

As at millions of dollars		**December 31 2024**		December 31 2023
Materials	**$**	**453**	$	408
Fuel		**328**		382
Total	**$**	**781**	$	790

16. DERIVATIVE INSTRUMENTS

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets				**Derivative Liabilities**			
As at millions of dollars		**December 31 2024**		December 31 2023		**December 31 2024**		December 31 2023
Regulatory deferral:								
Commodity swaps and forwards	**$**	**25**	$	16	**$**	**44**	$	76
FX forwards		**27**		3		**3**		3
		52		19		**47**		79
HFT derivatives:								
Power swaps and physical contracts		**34**		29		**30**		36
Natural gas swaps, futures, forwards, physical contracts		**236**		319		**660**		531
		270		348		**690**		567
Other derivatives:								
Equity derivatives		**-**		4		**2**		-
FX forwards		**-**		18		**34**		7
		-		22		**36**		7
Total gross current derivatives		**322**		389		**773**		653
Impact of master netting agreements:								
Regulatory deferral		**(7)**		(3)		**(7)**		(3)
HFT derivatives		**(148)**		(146)		**(148)**		(146)
Total impact of master netting agreements		**(155)**		(149)		**(155)**		(149)
Less: Derivatives classified as held for sale (1)		**(1)**		-		**(1)**		-
Total derivatives	**$**	**166**	$	240	**$**	**617**	$	504
Current (2)		**115**		174		**526**		386
Long-term (2)		**51**		66		**91**		118
Total derivatives	**$**	**166**	$	240	**$**	**617**	$	504

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.
(2) Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of $19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles. As of December 31, 2024, the unrealized gain in AOCI was $12 million, after-tax (December 31, 2023 – $14 million, after-tax). For the year ended December 31, 2024, unrealized gains of $2 million (2023 – $2 million) have been reclassified from AOCI into interest expense, net. The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months.

Regulatory Deferral

The Company has recorded the following changes with respect to derivatives receiving regulatory deferral:

millions of dollars	**Commodity swaps and forwards**	**FX forwards**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the year ended December 31		**2024**			2023
Unrealized gain (loss) in regulatory assets	**$ (27)**	**$ 5**	$ -	$ (109)	$ (3)
Unrealized gain (loss) in regulatory liabilities	**11**	**33**	(3)	(73)	-
Realized gain in regulatory assets	**(8)**	**-**	-	(5)	-
Realized loss in regulatory liabilities	**4**	**-**	-	2	-
Realized (gain) loss in inventory (1)	**11**	**(8)**	-	4	(10)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**50**	**(6)**	(49)	(9)	(4)
Other	**-**	**-**	-	(14)	-
Total change in derivative instruments	**$ 41**	**$ 24**	$ (52)	$ (204)	$ (17)

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period and hedging relationships that have been terminated or the hedged transaction is no longer probable.

As at December 31, 2024, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2025	2026-2027
Physical natural gas purchases:		
Natural gas (MMBtu)	6	-
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	21	23
Power (MWh)	1	-
Coal (metric tonnes)	1	-
FX forwards:		
FX contracts (millions of USD)	$ 208	$ 69
Weighted average rate	1.3361	1.3296
% of USD requirements	50%	17%

HFT Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives:

For the millions of dollars	Year ended December 31 **2024**	2023
Power swaps and physical contracts in non-regulated operating revenues	**$ 12**	$ (6)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**195**	1,043
Total gains in net income	**$ 207**	$ 1,037

As at December 31, 2024, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2025	2026	2027	2028	2029 and thereafter
Natural gas purchases (Mmbtu)	262	111	43	30	73
Natural gas sales (Mmbtu)	299	69	16	8	4
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at December 31, 2024, the Company had equity derivatives in place to manage cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 2.9 million shares and extends until December 2025. The FX forwards have a combined notional amount of $520 million USD and expire in 2025 through 2026.

For the				
			Year ended December 31	
millions of dollars		**2024**		2023
	FX Forwards	**Equity Derivatives**	FX Forwards	Equity Derivatives
Unrealized gain (loss) in OM&G	**$ -**	**$ (2)**	$ -	$ 4
Unrealized gain (loss) in other income, net	**(44)**	**-**	28	-
Realized gain (loss) in OM&G	**-**	**16**	-	(13)
Realized loss in other income, net	**(12)**	**-**	(11)	-
Total gains (losses) in net income	**$ (56)**	**$ 14**	$ 17	$ (9)

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high-risk accounts.

The Company assesses the potential for credit losses on a regular basis and, where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2024, the maximum exposure the Company had to credit risk was $1.3 billion (2023 – $1.2 billion), which included accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, FX and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2024 was $303 million (2023 – $310 million), which mitigated the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements, North American Energy Standards Board agreements and, or Edison Electric Institute agreements. The Company believes entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2024, the Company had $140 million (2023 – $142 million) in financial assets, considered to be past due, which have been outstanding for an average 61 days. The FV of these financial assets was $128 million (2023 – $127 million), the difference of which was included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

Concentration Risk

The Company's concentrations of risk consisted of the following:

As at	**December 31, 2024**		December 31, 2023	
	millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net				
Regulated utilities:				
Residential	**$ 376**	**22%**	$ 476	31%
Commercial	**184**	**11%**	194	13%
Industrial	**73**	**4%**	84	5%
Other	**105**	**6%**	103	7%
Cash collateral	**46**	**3%**	94	6%
	784	**46%**	951	62%
Trading group:				
Credit rating of A- or above	**88**	**5%**	47	3%
Credit rating of BBB- to BBB+	**42**	**2%**	33	2%
Not rated	**165**	**10%**	108	7%
	295	**17%**	188	12%
Other accounts receivable	**331**	**20%**	151	10%
Classification as assets held for sale (1)	**118**	**7%**	-	0%
	1,528	**90%**	1,290	84%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**91**	**5%**	138	9%
Credit rating of BBB- to BBB+	**1**	**0%**	7	1%
Not rated	**74**	**5%**	95	6%
	166	**10%**	240	16%
	$ 1,694	**100%**	$ 1,530	100%

(1) On August 5, 2024, Emera announced the sale of NMGC. As at December 31, 2024 NMGC's assets and liabilities were classified as held for sale. For further details, refer to note 4.

Cash Collateral

The Company’s cash collateral positions consisted of the following:

As at millions of dollars	**December 31 2024**	December 31 2023
Cash collateral provided to others	**$ 198**	$ 101
Cash collateral received from others	**$ 5**	$ 22

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2024, the total FV of derivatives in a liability position was $617 million (December 31, 2023 – $504 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

17. FV MEASUREMENTS

The Company is required to determine the FV of all derivatives except those which qualify for the NPNS exemption (see note 1) and uses a market approach to do so. The three levels of the FV hierarchy are defined as follows:

Level 1 – Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 – Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 – Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available and, accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the FV measurement.

The following tables set out the classification of the methodology used by the Company to FV its derivatives:

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2024 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 15	$ 3	$ -	$ 18
FX forwards	-	27	-	27
	15	30	-	45
HFT derivatives:				
Power swaps and physical contracts	2	23	5	30
Natural gas swaps, futures, forwards, physical contracts and related transportation	13	52	27	92
	15	75	32	122
Less: Derivatives classified as held for sale (1)	-	(1)	-	(1)
Total assets	30	104	32	166
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	$ 18	$ 19	$ -	$ 37
FX forwards	-	3	-	3
	18	22	-	40
HFT derivatives:				
Power swaps and physical contracts	2	21	4	27
Natural gas swaps, futures, forwards and physical contracts	(11)	89	437	515
	(9)	110	441	542
Other derivatives:				
FX forwards	-	34	-	34
Equity derivatives	2	-	-	2
	2	34	-	36
Less: Derivatives classified as held for sale (1)	-	(1)	-	(1)
Total liabilities	11	165	441	617
Net assets (liabilities)	$ 19	$ (61)	$ (409)	$ (451)

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2023 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 7	$ 6	$ -	$ 13
FX forwards	-	3	-	3
	7	9	-	16
HFT derivatives:				
Power swaps and physical contracts	(5)	23	-	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	42	108	34	184
	37	131	34	202
Other derivatives:				
FX forwards	-	18	-	18
Equity derivatives	4	-	-	4
	4	18	-	22
Total assets	48	158	34	240
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	43	30	-	73
FX forwards	-	3	-	3
	43	33	-	76
HFT derivatives:				
Power swaps and physical contracts	-	24	-	24
Natural gas swaps, futures, forwards and physical contracts	13	19	365	397
	13	43	365	421
Other derivatives:				
FX forwards	-	7	-	7
	-	7	-	7
Total liabilities	56	83	365	504
Net assets (liabilities)	$ (8)	$ 75	$ (331)	$ (264)

The change in the FV of the Level 3 financial assets and liabilities for the year ended December 31, 2024 was as follows:

		HFT Derivatives	
millions of dollars	Power	Natural gas	**Total**
Assets			
Balance, beginning of period	$ -	$ 34	**$ 34**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	5	(7)	**(2)**
Balance, December 31, 2024	**$ 5**	**$ 27**	**$ 32**
Liabilities			
Balance, beginning of period	$ -	$ 365	**$ 365**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	4	72	**76**
Balance, December 31, 2024	**$ 4**	**$ 437**	**$ 441**

Significant unobservable inputs used in the FV measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) FV measurement. Other unobservable inputs used include internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers.

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

millions of dollars	FV		Significant Unobservable Input	Low	High	Weighted average (1)
	Assets	**Liabilities**				
As at December 31, 2024						
HFT derivatives – Power swaps and physical contracts	**5**	**4**	Third-party pricing	$25.60	$139.65	$82.63
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**27**	**437**	Third-party pricing	$2.20	$17.54	$8.57
Total	**$ 32**	**$ 441**				
Net liability		**$ 409**				
As at December 31, 2023						
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	34	365	Third-party pricing	$1.27	$16.25	$4.85
Total	$ 34	$ 365				
Net liability		$ 331				

(1) Unobservable inputs were weighted by the relative FV of the instruments.

Long-term debt is a financial liability not measured at FV on the Consolidated Balance Sheets. The balance consisted of the following:

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
December 31, 2024	**$ 18,407**	**$ 17,941**	**$ -**	**$ 17,688**	**$ 253**	**$ 17,941**
December 31, 2023	$ 18,365	$ 16,621	$ -	$ 16,363	$ 258	$ 16,621

The Company has designated $1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. The Company's Hybrid Notes are contingently convertible into preferred shares in the event of bankruptcy or other related events. A redemption option on or after June 15, 2026 is available and at the control of the Company. The Hybrid Notes are classified as Level 2 financial assets. As at December 31, 2024, the FV of the Hybrid Notes was $1.2 billion (2023 – $1.2 billion). An after-tax foreign currency loss of $139 million was recorded in AOCI for the year ended December 31, 2024 (2023 – $38 million after-tax gain).

18. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Intercompany balances and intercompany transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are as follows:

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling a recovery of $324 million for the year ended December 31, 2024 (2023 – $163 million expense). NSPML is accounted for as an equity investment, and therefore corresponding earnings related to this revenue are reflected in Income from equity investments.

- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $11 million for the year ended December 31, 2024 (2023 – $14 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2024 and at December 31, 2023.

19. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars	**December 31 2024**	December 31 2023
Customer accounts receivable – billed	**$ 834**	$ 805
Customer accounts receivable – unbilled	**342**	363
Capitalized transportation capacity (1)	**216**	358
Cash collateral provided to others	**198**	101
Prepaid expenses	**105**	105
Income tax receivable	**22**	10
Allowance for credit losses	**(12)**	(15)
Other	**106**	90
Total receivables and other current assets	**$ 1,811**	$ 1,817

(1) Capitalized transportation capacity represents the value of transportation/storage received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

20. LEASES

Lessee

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 61 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.

As at millions of dollars	Classification	**December 31 2024**	December 31 2023
Right-of-use asset	Other long-term assets	**$ 52**	**$** 54
Lease liabilities			
Current	Other current liabilities	**3**	3
Long-term	Other long-term liabilities	**54**	55
Total lease liabilities		**$ 57**	**$** 58

The Company recorded lease expense of $123 million for the year ended December 31, 2024 (2023 – $127 million), of which $112 million (2023 – $119 million) related to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Minimum lease payments	$ 5	$ 3	$ 3	$ 3	$ 3	$ 115	$ 132
Less imputed interest							(75)
Total							$ 57

Additional information related to Emera's leases is as follows:

For the	Year ended December 31 **2024**	2023
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of dollars)	**$ 10**	$ 8
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of dollars)	**$ -**	$ 1
Weighted average remaining lease term (years)	**44**	44
Weighted average discount rate- operating leases	**3.96%**	3.93%

Lessor

The Company's net investment in direct finance and sales-type leases primarily relates to Brunswick Pipeline, Seacoast, compressed natural gas ("CNG") stations, a renewable natural gas ("RNG") facility and heat pumps.

The Company manages its risk associated with the residual value of the Brunswick Pipeline lease through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

Commencing in October 2023, the Company leased a RNG facility to a biogas producer that is classified as a sales-type lease. The term of the facility lease is 15 years, with a nominal value purchase at the end of the term and a net investment of approximately $35 million USD.

Direct finance and sales-type lease unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Operating revenues – regulated gas" and "Other income, net" on the Consolidated Statements of Income.

The total net investment in direct finance and sales-type leases consist of the following:

As at millions of dollars	**December 31 2024**	December 31 2023
Total minimum lease payment to be received	**$ 1,310**	$ 1,360
Less: amounts representing estimated executory costs	**(182)**	(190)
Minimum lease payments receivable	**$ 1,128**	$ 1,170
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: Credit loss reserve	**(2)**	(2)
Less: unearned finance lease income	**(655)**	(693)
Net investment in direct finance and sales-type leases	**$ 654**	$ 658
Principal due within one year (included in "Receivables and other current assets")	**44**	37
Net Investment in direct finance and sales type leases – long-term	**$ 610**	$ 621

As at December 31, 2024, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Minimum lease payments to be received	$ 99	$ 100	$ 99	$ 97	$ 96	$ 819	$ 1,310
Less: executory costs							(182)
Total							$ 1,128

21. PROPERTY, PLANT AND EQUIPMENT

PP&E consisted of the following regulated and non-regulated assets:

As at millions of dollars	Estimated useful life	**December 31 2024 (1)**	December 31 2023
Generation	5 to 131	**$ 14,297**	$ 13,500
Transmission	10 to 80	**3,106**	2,835
Distribution	10 to 65	**8,512**	7,417
Gas transmission and distribution	15 to 75	**4,658**	5,536
General plant and other (2)	2 to 60	**3,078**	2,985
Total cost		**33,651**	32,273
Less: Accumulated depreciation (2)		**(10,442)**	(9,994)
		23,209	22,279
Construction work in progress (2)		**2,959**	2,097
Net book value		**$ 26,168**	$ 24,376

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale and excluded from the table above. For further details on the pending transaction, refer to note 4.
(2) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2024, SeaCoast's share of plant in service was $27 million USD (2023 – $27 million USD), and accumulated depreciation of $3 million USD (2023 – $2 million USD). SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest were a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in "OM&G" in the Consolidated Statements of Income.

22. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") pension plans, which cover substantially all of its employees. The Company also provides non-pension benefits for its retirees.

Emera's net periodic benefit cost included the following:

Benefit Obligation and Plan Assets:
Changes in the benefit obligation and plan assets, and the funded status for plans were as follows:

For the millions of dollars				Year ended December 31
	2024		2023	
	DB pension plans	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO"):				
Balance, January 1	**$ 2,273**	**$ 227**	$ 2,158	$ 243
Service cost	**35**	**3**	30	3
Plan participant contributions	**6**	**5**	6	6
Interest cost	**110**	**12**	111	13
Plan amendments	**-**	**-**	-	(14)
Benefits paid	**(153)**	**(21)**	(147)	(29)
Actuarial losses (gains) (1)	**13**	**(3)**	146	10
Settlements and curtailments	**-**	**-**	(8)	-
FX translation adjustment	**83**	**18**	(23)	(5)
Balance, December 31	**$ 2,367**	**$ 241**	$ 2,273	$ 227
Change in plan assets:				
Balance, January 1	**$ 2,298**	**$ 48**	$ 2,163	$ 46
Employer contributions	**36**	**13**	42	23
Plan participant contributions	**6**	**5**	6	6
Benefits paid	**(153)**	**(21)**	(147)	(29)
Actual return on assets, net of expenses	**226**	**4**	262	3
Settlements and curtailments	**-**	**-**	(8)	**-**
FX translation adjustment	**80**	**5**	(20)	(1)
Balance, December 31	**$ 2,493**	**$ 54**	$ 2,298	$ 48
Funded status, end of year	**$ 126**	**$ (187)**	$ 25	$ (179)

(1) The actuarial losses recognized in the period are primarily due to changes in the discount rate, higher than expected indexation, and compensation-related assumption changes.

Plans with PBO/APBO in Excess of Plan Assets:
The aggregate financial position for pension plans where the PBO or APBO (for post-retirement benefit plans) exceeded the plan assets for the years ended December 31 were as follows:

millions of dollars	**2024**		2023	
	DB pension plans	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
PBO/APBO	**$ 95**	**$ 219**	$ 120	$ 205
FV of plan assets	**11**	**-**	37	-
Funded status	**$ (84)**	**$ (219)**	$ (83)	$ (205)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets:
The ABO for the DB pension plans was $2,255 million as at December 31, 2024 (2023 – $2,172 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 were as follows:

millions of dollars	**2024**	2023
	DB pension plans	DB pension plans
ABO	**$ 90**	$ 114
FV of plan assets	**11**	37
Funded status	**$ (79)**	$ (77)

Balance Sheet:
The amounts recognized in the Consolidated Balance Sheets consisted of the following:

As at millions of dollars		**December 31 2024**		December 31 2023
	DB pension plans	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
Other current liabilities	**$ (5)**	**$ (21)**	$ (5)	$ (18)
Liabilities associated with assets held for sale (1)	**-**	**(1)**	-	-
Long-term liabilities	**(78)**	**(196)**	(78)	(187)
Other long-term assets	**208**	**-**	108	26
Assets held for sale (1)	**1**	**31**	-	-
AOCI, net of tax and regulatory assets	**354**	**22**	385	20
Deferred income tax expense in AOCI	**(8)**	**(1)**	(8)	(1)
Net amount recognized	**$ 472**	**$ (166)**	$ 402	$ (160)

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

Amounts Recognized in AOCI and Regulatory Assets:
Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of dollars	Regulatory assets	Actuarial (gains) losses	Past service gains
DB Pension Plans:			
Balance, January 1, 2024	$ 324	$ 53	$ -
Amortized in current period	(9)	(3)	-
Current year additions	19	(67)	-
Change in FX rate	29	-	-
Balance, December 31, 2024	$ 363	$ (17)	$ -
Non-pension benefits plans:			
Balance, January 1, 2024	$ 29	$ (8)	$ (2)
Amortized in current period	2	1	2
Current year reductions	(5)	(1)	-
Change in FX rate	3	-	-
Balance, December 31, 2024	$ 29	$ (8)	$ -

As at millions of dollars		**December 31 2024**		December 31 2023
	DB pension plans	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
Actuarial (gains) losses	**$ (17)**	**(8)**	$ 53	(8)
Past service gains	**-**	**-**	-	(2)
Deferred income tax expense	**8**	**1**	8	1
AOCI, net of tax	**(9)**	**(7)**	61	(9)
Regulatory assets	**363**	**29**	324	29
AOCI, net of tax and regulatory assets	**$ 354**	**$ 22**	$ 385	$ 20

Benefit Cost Components:
Emera's net periodic benefit cost included the following:

As at millions of dollars		**2024**		Year ended December 31 2023
	DB pension plans	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
Service cost	**$ 35**	**$ 3**	$ 30	$ 3
Interest cost	**110**	**12**	111	13
Expected return on plan assets	**(160)**	**(2)**	(161)	(2)
Current year amortization of:				
Actuarial losses (gains)	**3**	**(2)**	1	(3)
Past service gains	**-**	**(2)**	-	-
Regulatory assets	**9**	**(2)**	6	(2)
Settlement, curtailments	**-**	**1**	2	-
Total	**$ (3)**	**$ 8**	$ (11)	$ 9

The expected return on plan assets is determined based on the market-related value of plan assets of $2,571 million as at January 1, 2024 (2023 – $2,577 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a multi-year period.

Pension Plan Asset Allocations:
Emera’s investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan’s actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Further, within each asset class, a diversification is undertaken through the investment in a broad range of investment and non-investment grade securities. Emera’s target asset allocation is as follows:

Asset Class	Target Range at Market		
Canadian Pension Plans:			
Short-term securities	0%	to	10%
Fixed income	34%	to	49%
Equities:			
Canadian	5%	to	15%
Non-Canadian	37%	to	61%
Non-Canadian Pension Plans:			
Cash and cash equivalents	0%	to	10%
Fixed income	29%	to	49%
Equities	48%	to	68%

Pension plan assets are overseen by the respective management pension committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

The following tables set out the classification of the methodology used by the Company to FV its investments (for more information on the FV hierarchy and measurement, refer to note 17):

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
As at					**December 31, 2024**
Cash and cash equivalents	**$ -**	**$ 39**	**$ -**	**$ 39**	**2 %**
Net in-transits	**-**	**(27)**	**-**	**(27)**	**(1)%**
Equity securities:					
Canadian equity	**-**	**109**	**-**	**109**	**4 %**
United States equity	**-**	**312**	**-**	**312**	**12 %**
Other equity	**-**	**140**	**-**	**140**	**5 %**
Fixed income securities:					
Government	**-**	**-**	**132**	**132**	**5 %**
Corporate	**-**	**-**	**92**	**92**	**4 %**
Other	**-**	**-**	**22**	**22**	**1 %**
Mutual funds	**-**	**13**	**-**	**13**	**1 %**
Open-ended investments measured at NAV (1)	**1,142**	**-**	**-**	**1,142**	**46 %**
Common collective trusts measured at NAV (2)	**519**	**-**	**-**	**519**	**21 %**
Total	**$ 1,661**	**$ 586**	**$ 246**	**$ 2,493**	**100 %**

As at					December 31, 2023
Cash and cash equivalents	$ -	$ 40	$ -	$ 40	2 %
Net in-transits	-	(9)	-	(9)	- %
Equity securities:					
Canadian equity	-	96	-	96	4 %
United States equity	-	141	-	141	6 %
Other equity	-	112	-	112	5 %
Fixed income securities:					
Government	-	-	172	172	8 %
Corporate	-	-	90	90	4 %
Other	-	4	5	9	- %
Mutual funds	-	50	-	50	2 %
Other	-	6	(1)	5	- %
Open-ended investments measured at NAV (1)	1,006	-	-	1,006	44 %
Common collective trusts measured at NAV (2)	586	-	-	586	25 %
Total	$ 1,592	$ 440	$ 266	$ 2,298	100 %

(1) Net asset value ("NAV") investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated at least monthly and the funds honour subscription and redemption activity regularly.
(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honour subscription and redemption activity regularly.

Non-Pension Benefit Plans:
There are no assets set aside to pay for most of the Company's non-pension benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The exception to this is the NMGC Retiree Medical Plan, which is fully funded.

Investments in Emera:
As at December 31, 2024 and 2023, assets related to the pension funds and post-retirement benefit plans did not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Cash Flows:
The following table shows expected cash flows for DB pension and other post-retirement benefit plans:

millions of dollars	DB pension plans	Non-pension benefit plans
Expected employer contributions		
2025	$ 41	$ 21
Expected benefit payments		
2025	175	23
2026	179	23
2027	182	23
2028	184	23
2029	186	22
2030 – 2034	950	103

Assumptions:
The following table shows the assumptions that have been used in accounting for DB pension and other post-retirement benefit plans:

		2024		2023
(weighted average assumptions)	**DB pension plans**	**Non-pension benefit plans**	DB pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate - past service	**5.07 %**	**4.91 %**	4.89 %	4.89 %
Discount rate - future service	**5.12 %**	**5.00 %**	4.88 %	4.89 %
Rate of compensation increase	**3.73 %**	**3.72 %**	3.87 %	3.85 %
Health care trend - initial (next year)	**-**	**6.53 %**	-	6.04 %
- ultimate	**-**	**3.77 %**	-	3.76 %
- year ultimate reached		**2044**		2043
Benefit cost for year ended December 31:				
Discount rate - past service	**4.89 %**	**4.89 %**	5.33 %	5.31 %
Discount rate - future service	**4.88 %**	**4.89 %**	5.34 %	5.32 %
Expected long-term return on plan assets	**6.43 %**	**3.69 %**	6.56 %	2.16 %
Rate of compensation increase	**3.87 %**	**3.85 %**	3.62 %	3.61 %
Health care trend - initial (current year)	**-**	**6.04 %**	-	5.40 %
- ultimate	**-**	**3.76 %**	-	3.77 %
- year ultimate reached		**2043**		2043

Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

DC Pension Plan:
Emera also provides a DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2024 was $51 million (2023 – $45 million).

23. GOODWILL

The change in goodwill for the year ended December 31 was due to the following:

millions of dollars		**2024**		2023
Balance, January 1	**$**	**5,871**	$	6,012
Change in FX rate		**504**		(141)
Impairment charges		**(214)**		-
Classified as assets held for sale (1)		**(303)**		-
Balance, December 31	**$**	**5,858**	$	5,871

(1) As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2024, related to TECO Energy, Inc. (reporting units with goodwill are TEC, PGS, and NMGC).

On August 5, 2024, Emera announced an agreement to sell NMGC. As the expected transaction proceeds on the pending sale will be less than the NMGC carrying amount, the Company performed a quantitative goodwill impairment assessment for the NMGC reporting unit. It was determined that the NMGC carrying amount exceeded the FV of the expected transaction proceeds, and as a result, a non-cash goodwill impairment charge of $210 million, pre-tax, was recorded in Q3 2024, reducing the NMGC reporting unit goodwill balance to $303 million as at December 31, 2024. This non-cash charge is included in "Impairment charges" on the Consolidated Statements of Income.

In 2024, a qualitative assessment was performed for TEC given the significant excess of FV over carrying amounts calculated during the last quantitative test in Q4 2023. Management concluded it was more likely than not that the FV of this reporting unit exceeded its carrying amount, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the PGS reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2024 using a combination of the income and market approach. This assessment estimated that the FV of the PGS reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

24. SHORT-TERM DEBT

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

millions of dollars		2024	Weighted average interest rate		2023	Weighted average interest rate
Florida Electric Utility						
Advances on revolving credit facilities	**$**	**915**	**4.77 %**	$	277	5.68 %
Gas Utilities and Infrastructure						
PGS – Advances on revolving credit facilities		**199**	**5.36 %**		73	6.36 %
NMGC – Advances on revolving credit facilities		**46**	**5.52 %**		25	6.46 %
Other Electric Utilities						
GBPC – Advances on revolving credit facilities		**19**	**7.20 %**		8	5.54 %
Other						
TECO Finance – Advances on revolving credit and term facilities		**265**	**5.53 %**		245	6.54 %
Emera – Bank indebtedness		**2**	**- %**		9	- %
Emera – Non-revolving term facilities		**-**	**- %**		796	6.07 %
	$	**1,446**		$	1,433	
Adjustment						
Classification as liabilities held for sale (1)		**(46)**			-	
Short-term debt	**$**	**1,400**		$	1,433	

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

The Company's total short-term unsecured revolving and non-revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity		2024		2023
TEC – committed revolving credit facility	2028	**$**	**1,151**	$	401
TECO Finance – committed revolving credit facility	2028		**576**		529
PGS – revolving credit facility	2028		**360**		331
NMGC – revolving credit facility	2026		**180**		165
Emera – non-revolving term facility	2024		**-**		400
Emera – non-revolving term facility	2024		**-**		400
TEC – revolving facility	2024		**-**		265
TEC – revolving facility	2024		**-**		265
Other – committed revolving credit facilities	Various		**35**		17
Total		**$**	**2,302**	$	2,773
Less:					
Advances under revolving credit and term facilities			**1,400**		1,433
Letters of credit issued within the credit facilities			**4**		3
Total advances under available facilities			**1,404**		1,436
Available capacity under existing agreements		**$**	**898**	$	1,337

The weighted average interest rate on outstanding short-term debt at December 31, 2024 was 5.05 per cent (2023 – 5.95 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

On April 1, 2024, TEC amended its $800 million USD unsecured committed revolving credit facility to extend the maturity date from December 17, 2026 to December 1, 2028. There were no other changes in commercial terms from the prior agreement.

Other

On June 24, 2024, Emera repaid its $400 million unsecured non-revolving term facility set to mature in August 2024.

On June 17, 2024, Emera repaid $200 million on the December 2024 unsecured non-revolving term facility, decreasing the facility from $400 million to $200 million. In December 2024, Emera repaid the $200 million upon maturity.

On April 1, 2024, TECO Finance amended its $400 million USD unsecured committed revolving credit facility to extend the maturity date from December 17, 2026 to December 1, 2028. There were no other changes in commercial terms from the prior agreement.

25. OTHER CURRENT LIABILITIES

As at millions of dollars	**December 31 2024**	December 31 2023
Accrued charges	**$ 189**	$ 172
Accrued interest on long-term debt	**106**	107
Pension and post-retirement liabilities (note 22)	**26**	23
Sales and other taxes payable	**11**	11
Income tax payable	**4**	2
Other	**153**	112
	$ 489	$ 427

26. LONG-TERM DEBT

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31 consisted of the following:

millions of dollars	Weighted average interest rate (1) 2024	2023	Maturity		2024		2023
Florida Electric Utility							
Senior unsecured notes	4.36%	4.61%	2029 - 2051	**$**	**5,720**	$	5,654
Canadian Electric Utilities							
NSPI – Commercial paper (2)	Variable	Variable	2029	**$**	**177**	$	721
NSPI – Senior unsecured notes	5.12%	5.13%	2025 - 2097		**3,184**		3,165
				$	**3,361**	$	3,886
Gas Utilities and Infrastructure							
PGS – Senior unsecured notes	5.63%	5.63%	2028 - 2053	**$**	**1,331**	$	1,223
NMGC – Senior unsecured notes	3.78%	3.78%	2026 - 2051		**698**		642
NMGC – Unsecured loan notes	N/A	Variable	2024		**-**		30
NMGI – Senior unsecured notes	N/A	3.64%	2024		**-**		198
EBP – Secured loan notes	Variable	Variable	2028		**250**		246
				$	**2,279**	$	2,339
Other Electric Utilities							
Unsecured loan notes	4.06%	4.78%	2025 - 2028	**$**	**143**	$	121
Unsecured loan notes	Variable	Variable	2025 - 2027		**104**		104
Secured senior notes and debentures (3)	2.38%	3.06%	2026 - 2040		**169**		197
				$	**416**	$	422
Other							
Unsecured loan notes	Variable	Variable	2026 - 2029	**$**	**992**	$	465
Senior unsecured notes	3.99%	3.65%	2026 - 2046		**3,525**		3,637
Senior unsecured notes	4.84%	4.84%	2030		**500**		500
Fixed to floating subordinated notes (4)	6.75%	6.75%	2076		**1,727**		1,587
Junior subordinated notes	7.63%	0.00%	2054		**720**		-
				$	**7,464**	$	6,189
Adjustments							
Debt issuance costs					**(137)**		(125)
Classification as liabilities held for sale (5)					**(696)**		-
Amount due within one year (6)					**(234)**		(676)
				$	**(1,067)**	$	(801)
Long-Term Debt				**$**	**18,173**	$	17,689

(1) Weighted average interest rate of fixed rate long-term debt.

(2) Discount notes are backed by a revolving credit facility which matures in 2029.

(3) Notes are issued and payable in either USD or BBD.

(4) In 2024, the Company recognized $110 million in interest expense (2023 – $109 million) related to its fixed to floating subordinated notes.

(5) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

(6) Excludes NMGC amounts which are classified as current liabilities associated with assets held for sale.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity	2024	2023
Emera – committed revolving credit facility (1)	June 2029	**$ 1,300**	$ 900
NSPI – revolving credit facility (1)	June 2029	**800**	800
Emera – Unsecured non-revolving credit facility	February 2026	**200**	400
TEC – Unsecured committed revolving credit facility	December 2026	**-**	657
NSPI – non-revolving credit facility	July 2024	**-**	400
NMGC – Unsecured non-revolving credit facility	March 2024	**-**	30
ECI – revolving credit facilities	October 2024	**-**	10
Total		**$ 2,300**	$ 3,197
Less:			
Borrowings under credit facilities		**1,169**	1,884
Letters of credit issued inside credit facilities		**12**	6
Use of available facilities		**$ 1,181**	$ 1,890
Available capacity under existing agreements		**$ 1,119**	$ 1,307

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million.

Debt Covenants

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenants are listed below:

	Financial Covenant	Requirement	As at December 31, 2024
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.55 : 1

Recent Significant Financing Activity by Segment

Florida Electric Utility

On July 12, 2024, TEC repaid a $300 million USD note upon maturity. This note was repaid with proceeds from commercial paper.

On January 30, 2024, TEC issued $500 million USD of senior unsecured bonds that bear interest at 4.90 per cent with a maturity date of March 1, 2029. Proceeds from the issuance were primarily used for the repayment of short-term borrowings outstanding under the 5-year credit facility.

Canadian Electric Utilities

On June 24, 2024, NSPI amended its unsecured non-revolving credit facility to extend the maturity date from July 15, 2024 to June 24, 2025 and reduce the facility from $400 million to $300 million. On December 16, 2024, NSPI repaid the $300 million unsecured non-revolving credit facility.

On June 24, 2024, NSPI amended its unsecured committed revolving credit facility to extend the maturity date from December 16, 2027 to June 24, 2029. There were no other material changes in commercial terms from the prior agreement.

On June 13, 2024, NSPI entered a non-revolving credit facility to finance the Battery Energy Storage Project. NSPI can request funds under the facility quarterly for amounts related to incurred project costs up to the total commitment of the lessor of $120 million and 45.06 per cent of the total eligible project costs over the term of the agreement. The facility will be available until 6 months after completion of the project, not to exceed May 21, 2027, and matures 20 years following the end of the period. As at December 31, 2024, NSPI had utilized $19 million from the facility, which bears interest at 2.51 per cent.

Gas Utilities and Infrastructure

On December 10, 2024, Brunswick Pipeline amended its non-revolving loan agreement. The maturity date was extended to December 2028 and now includes annual principal repayments.

On July 30, 2024, New Mexico Gas Intermediate, Inc. repaid its $150 million USD fixed rate notes upon maturity.

Other Electric Utilities

On May 2, 2024, BLPC amended its $92 million Barbadian dollar ($46 million USD) loan facility to extend the maturity date from February 19, 2025 to July 19, 2028. There were no other material changes in commercial terms from the prior agreement.

Other

On June 24, 2024, Emera amended its unsecured committed revolving credit facility increasing the facility from $900 million to $1,300 million. Emera also extended the maturity date from June 24, 2027 to June 24, 2029. There were no other material changes in commercial terms from the prior agreement.

On June 15, 2024, Emera Finance repaid its $300 million USD senior notes upon maturity.

On June 18, 2024, EUSHI Finance, Inc., completed an issuance of $500 million USD fixed-to-fixed reset rate junior subordinated notes. The notes initially bear interest at a rate of 7.625 per cent, and will reset on December 15, 2029, and every five years thereafter, to a rate per annum equal to the five-year U.S. treasury rate plus 3.136 per cent. The notes mature on December 15, 2054. EUSHI Finance, Inc., at its option, may redeem the notes, in whole or in part, 90 days prior to the first interest reset date, and any semi-annual interest payment date thereafter, at a redemption price equal to the principal amount.

On February 16, 2024, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from February 19, 2024 to February 19, 2025. There were no other changes in commercial terms from the prior agreement. On July 19, 2024, Emera reduced the amount of the facility from $400 million to $200 million. On February 20, 2025, Emera extended the agreement for an additional year to February 2026 with no other changes in terms. This facility was classified as long-term debt at December 31, 2024.

Long-Term Debt Maturities

As at December 31, 2024, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Florida Electric Utility	$ -	$ -	$ -	$ -	$ 720	$ 5,000	$ 5,720
Canadian Electric Utilities	125	40	-	-	217	2,979	3,361
Gas Utilities and Infrastructure	31	132	31	535	31	1,519	2,279
Other Electric Utilities	78	101	89	116	4	28	416
Other	-	3,006	-	-	792	3,666	7,464
Total	$ 234	$ 3,279	$ 120	$ 651	$ 1,764	$ 13,192	$ 19,240

27. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the FV of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of dollars		**2024**		2023
Balance, January 1	**$**	**192**	$	174
Additions		**11**		-
Accretion included in depreciation expense		**10**		9
Change in FX rate		**5**		(1)
Revisions in estimated cash flows		**2**		-
Accretion deferred to regulatory asset (included in PP&E)		**-**		18
Classified as assets held for sale (1)		**(1)**		-
Liabilities settled		**(2)**		(8)
Balance, December 31	**$**	**217**	$	192

(1) As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

28. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2024, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars		2025		2026		2027		2028		2029		Thereafter		Total
Purchased power (1)	$	307	$	277	$	368	$	368	$	369	$	4,487	$	6,176
Transportation (2)(3)		742		545		544		454		412		3,228		5,925
Capital projects		604		287		24		-		-		-		915
Fuel, gas supply and storage (4)		591		94		21		5		-		-		711
Other		160		95		80		59		59		264		717
	$	2,404	$	1,298	$	1,037	$	886	$	840	$	7,979	$	14,444

As detailed below, contractual obligations at December 31, 2024 includes those related to NMGC. On completion of the sale of NMGC, all remaining future contractual obligations will be transferred to the buyer. For further details on the pending transaction, refer to note 4.

(1) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.

(2) Includes $86 million related to NMGC (2025: $30 million, 2026: $24 million, 2027: $16 million, 2028: $12 million, 2029: $4 million).

(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $135 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(4) Includes $177 million related to NMGC (2025: $109 million, 2026: $52 million, 2027: $13 million, 2028: $3 million)

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In November 2024, the UARB approved the collection of up to $197 million from NSPI for the recovery of Maritime Link costs in 2025. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Emera has committed to obtain certain transmission rights in New Brunswick during summer periods (April through October, inclusive) for NLH's use, if requested, effective August 15, 2021 and continuing for 50 years. As transmission rights are contracted, the obligations are included within “Other” in the above table.

B. Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at December 31, 2024, the aggregate financial liability of the Florida utilities is estimated to be $17 million ($12 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of the cleanup costs attributable to the Florida utilities. The estimates to perform the work are based on the Florida utilities' experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are believed to be currently credit-worthy and are likely to continue to be credit-worthy for the duration of the remediation work. However, in those instances that they are not, the Florida utilities could be liable for more than their actual percentage of the remediation costs. Other factors that could impact these estimates include additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in base rate proceedings.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Principal Financial Risks and Uncertainties

Emera believes the following principal financial risks could have a material adverse effect on Emera or its subsidiaries, or their business operations, liquidity or access to or cost of capital, financial position, prospects, and/or results of operations (herein considered a "Material Adverse Effect"). Risks associated with derivative instruments and FV measurements are discussed in note 16 and note 17.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board of Directors, to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls. The Board of Directors has a Risk and Sustainability Committee ('RSC") to assist in carrying out its risk and sustainability oversight responsibilities. The RSC's mandate includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments are subject to complex legislative and regulatory frameworks that cover material aspects of their businesses. These frameworks influence key factors such as rates and cost structures, revenue requirements, allowed ROEs, capital structures, rate base and capital investments, and the recovery of purchased electricity and fuel costs and other costs. Regulators also review the prudency of costs and make other decisions that can impact customer rates and the reliability of service. Emera's cost-of-service utilities must obtain regulatory approvals for material aspects of their businesses, including changing or adding rates and/or riders. Such approvals often require public hearing proceedings involving numerous stakeholders, and there is no assurance in the outcomes or impact of any regulatory process or decision.

If Emera is unable to recover in a timely manner a material amount of costs or a return on invested capital through regulatory mechanisms or otherwise, is disallowed the recovery of certain costs, is subject to regulatory penalties, is not permitted to make certain capital investments, or is not permitted to invest in or divest certain utility assets, it could result in a Material Adverse Effect, including valuation impairments. Regulatory lag, the time between the incurrence of costs and the granting of the rates to recover those costs by regulators, may also result in a Material Adverse Effect.

Aspects of the acquisition, ownership, operations, siting, planning, construction, and decommissioning of electric generation, storage, transmission and distribution facilities and natural gas transportation and distribution systems are also subject to regulatory processes and approvals of regulators, government departments and agencies, and other third parties. The failure to obtain, maintain, and renew such approvals or significant changes in the terms and conditions thereof could have a Material Adverse Effect.

The regulatory framework, process and regulatory decisions may also be adversely affected by changes in government, shifts in government or public policy, legislative changes, regulatory decisions, geopolitical changes, changes in the economic environment, or other factors. Government interference in the regulatory process or regulatory decisions can undermine regulatory stability, predictability, and independence. Any such changes could have a Material Adverse Effect.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, with a significant amount of the Company's net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the CAD and, particularly, the USD, which could positively or adversely affect results.

Emera manages currency risks through matching US denominated debt to finance its US operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter FX forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenue streams and capital expenditures, and on net income earned outside of Canada. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including FX.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in AOCI.

Liquidity and Capital Markets Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by various market analysts, including credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in PP&E and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business, its regulatory framework and legislative environment, political interference in the regulatory process, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increased borrowing costs under certain existing credit facilities, limit access to the commercial paper market, or limit the availability of adequate credit support for subsidiary operations. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation.

General Economic Risk

The Company has exposure to the macro-economic conditions in North America and in other geographic regions in which Emera operates. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity and natural gas and, in turn, the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could have a Material Adverse Effect. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

Interest Rate Risk:
Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Markets Risk".

As with most other utilities and other similar yield-returning investments, Emera's share price may be affected by changes in interest rates and could underperform the market in an environment of rising interest rates.

Inflation Risk:
The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates.

Commodity Price Risk

The Company’s utility fuel supply and purchase of other commodities is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

Regulated Utilities:
The Company’s utility fuel supply is exposed to broader global market conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to, currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks, such as political instability, conflicts, changes to international trade agreements, tariffs, trade sanctions or embargos.

Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales, any of which could result in a Material Adverse Effect.

Emera Energy Marketing and Trading:
The majority of Emera Energy’s portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets in the event of an operational issue, imposition of tariffs or counterparty default. Changes in commodity prices can also result in increased collateral requirements associated with physical contracts and financial hedges, resulting in higher liquidity requirements and increased costs to the business.

Income Tax Risk

The computation of the Company’s provision for income taxes is impacted by changes in tax legislation in Canada, the US and the Caribbean and any such changes could have a Material Adverse Effect. The value of Emera’s existing deferred income tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws.

D. Guarantees and Letters of Credit

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit were not included within the Consolidated Balance Sheets as at December 31, 2024:

TECO Holdings, Inc. (“TECO Holdings”) has a guarantee in connection with SeaCoast’s performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which was terminated on January 1, 2022. The counterparty has the right to require TECO Holdings to provide replacement credit support either in the form of a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $27 million USD.

TECO Holdings has a guarantee in connection with SeaCoast’s performance obligations under a firm service agreement, which expires December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of $13 million USD if SeaCoast fails to pay or perform under the firm service agreement. The counterparty has the right to require TECO Holdings to provide replacement credit support in the form of either a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $13 million USD.

Emera has a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

NSPI has guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2023 – $104 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $105 million USD (December 31, 2023 – $103 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

Emera, on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2025. The amount committed as at December 31, 2024 was $58 million (December 31, 2023 – $56 million).

Emera has provided an indemnity to a counterparty in relation to certain future tax amounts that could arise from specific future changes in Canadian federal law, subject to certain conditions and limitations. No such changes in law have been proposed at this time. A reasonable estimate of the potential amount of future payments that could result from future claims under this indemnity cannot be calculated, but the risk of having to make any significant payments under this indemnity is considered to be remote.

Collaborative Arrangements

For the years ended December 31, 2024 and 2023, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party’s project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI’s portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI’s portion of operating expenses is recorded in “OM&G” on the Consolidated Statements of Income. In 2024, NSPI recognized $12 million net expense (2023 – $8 million) in “Regulated fuel for generation and purchased power” and $3 million (2023 – $3 million) in “OM&G” on the Consolidated Statements of Income.

29. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

	Annual Dividend Per Share	Redemption Price per share	**December 31, 2024** Issued and Outstanding	Net Proceeds	December 31, 2023 Issued and Outstanding	Net Proceeds
Series A	$ 0.5456	$ 25.00	**4,866,814**	**$ 119**	4,866,814	$ 119
Series B	Floating	$ 25.00	**1,133,186**	**$ 28**	1,133,186	$ 28
Series C	$ 1.6085	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.5810	$ 25.00	**12,000,000**	**$ 295**	12,000,000	$ 295
Series J	$ 1.0625	$ 25.00	**8,000,000**	**$ 196**	8,000,000	$ 196
Series L	$ 1.1500	$ 26.00	**9,000,000**	**$ 222**	9,000,000	$ 222
Total			**58,000,000**	**$ 1,422**	58,000,000	$ 1,422

Characteristics of the First Preferred Shares:

First Preferred Shares (1)(2)	Annual Dividend Rate (%)	Current Annual Dividend ($)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a one for one basis
Fixed rate reset (3)(4)						
Series A	2.182	0.5456	1.84	August 15, 2025	25.00	Series B
Series C	6.434	1.6085	2.65	August 15, 2028	25.00	Series D
Series F (5)(6)	4.202	1.0505	2.63	February 15, 2025	25.00	Series G
Minimum rate reset (3)(4)						
Series B	2.393	Floating	1.84	August 15, 2025	25.00	Series A
Series H	6.324	1.5810	4.90	August 15, 2028	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (7)	4.500	1.1250			25.00	
Series L (8)	4.600	1.1500		November 15, 2026	26.00	

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.

(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preferred 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.

(3) On the redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent) and for Series B equals the Government of Treasury Bill Rate on the applicable reset date, plus 1.84 per cent.

(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 Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series D, Series G and Series I shares without the consent of the holder every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2028, February 15, 2025 and August 15, 2028, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.

(5) On January 8, 2025, Emera announced that it would not redeem the outstanding Preferred Shares, Series F on February 15, 2025. During the conversion period between January 15, 2025 and January 31,2025, subject to certain conditions, the holders of Series F shares had the right, at their option, to convert all or any of their Series F shares, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series G on February 15, 2025. On February 6, 2025, Emera announced after having taken into account all conversion notices received from holders, no Series F were converted into Series G shares.

(6) On January 16, 2025, Emera announced that the annual fixed dividend per share for Series F shares will be reset from $1.0505 to $1.4372 for the five-year period from and including February 15, 2025.

(7) First Preferred Shares, Series E are redeemable at $25.00 per share.

(8) First Preferred Shares, Series L are redeemable at $26.00 on or after November 15, 2026 to November 15, 2027, decreasing $0.25 each year until November 15, 2030 and $25.00 per share thereafter.

First Preferred Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends are deducted on the Consolidated Statements of Income before arriving at “Net income attributable to common shareholders” and shown on the Consolidated Statement of Changes in Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

30. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of dollars	**December 31 2024**	December 31 2023
Preferred shares of GBPC	**$ 14**	$ 14
	$ 14	$ 14

Preferred shares of GBPC:

Authorized:
10,000 non-voting cumulative redeemable variable perpetual preferred shares.

		2024		2023
Issued and outstanding:	**number of shares**	**millions of dollars**	number of shares	millions of dollars
Outstanding as at December 31	**10,000**	**$ 14**	10,000	$ 14

GBPC Non–Voting Cumulative Variable Perpetual Preferred Stock:

The preferred shares are redeemable by GBPC after June 17, 2021, at $1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually.

The Preferred Shares rank behind GBPC’s current and future secured and unsecured debt and ahead of all of GBPC’s current and future common stock.

31. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of dollars		Year ended December 31 2024		2023
Changes in non-cash working capital:				
Inventory	**$**	**38**	$	(31)
Receivables and other current assets (1)		**(154)**		653
Accounts payable		**536**		(538)
Other current liabilities (2)		**32**		(179)
Total non-cash working capital	**$**	**452**	$	(95)

(1) The year ended December 31, 2023, includes $162 million related to the January 2023 NMGC gas hedges. Offsetting change in regulatory liabilities is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) The year ended December 31, 2023, includes ($166) million related to the decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the millions of dollars		Year ended December 31 2024		2023
Supplemental disclosure of cash paid:				
Interest	**$**	**989**	$	930
Income taxes	**$**	**34**	$	43
Supplemental disclosure of non-cash activities:				
Accrued proceeds from disposal of investment subject to significant influence	**$**	**25**	$	-
Common share dividends reinvested	**$**	**291**	$	271
Reclassification of short-term debt to long-term debt	**$**	**-**	$	657
Decrease in accrued capital expenditures	**$**	**-**	$	(19)
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**(118)**	$	123

32. STOCK-BASED COMPENSATION

ECSPP and Common Shareholders DRIP

Eligible employees can participate in the ECSPP. As of December 31, 2024, the plan allows employees to make cash contributions of a minimum of $25 per month to a maximum of $20,000 CAD or $15,000 USD per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows reinvestment of dividends for all participants except for where prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2024, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSPP for the year ended December 31, 2024 was $4 million (2023 – $3 million) and was included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders DRIP, which provides an opportunity for shareholders residing in Canada to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased with the reinvestment of cash dividends. The discount was 2 per cent in 2024.

Stock-Based Compensation Plans

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2024, Emera was in compliance with this requirement.

Stock options granted in 2021 and prior vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 per cent increments on the first, second, third, fourth and fifth anniversaries of the date of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

For stock options granted in 2021 and prior, unless a stock option has expired, vested options may be exercised within the 27 months following the option holder's date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. Commencing with the 2022 stock option grant, vested options may be exercised during the full term of the option following the option holders date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

The following table shows the weighted average FV per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

		2024		2023
Weighted average FV per option	**$**	**4.66**	$	6.32
Expected term (1)		**5 years**		5 years
Risk-free interest rate (2)		**3.56 %**		3.53 %
Expected dividend yield (3)		**6.11 %**		5.05 %
Expected volatility (4)		**20.67 %**		20.07 %

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.
(2) Based on the Bank of Canada five-year government bond yields.
(3) Incorporates current dividend rates and historical dividend increase patterns.
(4) Estimated using the five-year historical volatility.

The following table summarizes stock option information for 2024:

	Total Options		Non-Vested Options(1)	
	Number of Options	Weighted average exercise price per share	Number of Options	Weighted average grant date fair-value
Outstanding as at December 31, 2023	3,095,604	$ 51.20	1,253,255	$ 5.17
Granted	792,600	46.97	792,600	4.66
Exercised	(78,839)	39.86	N/A	N/A
Forfeited	(13,325)	56.14	-	N/A
Vested	N/A	N/A	(438,365)	4.58
Options outstanding December 31, 2024	**3,796,040**	**$ 50.53**	**1,607,490**	**$ 5.08**
Options exercisable December 31, 2024 (2)(3)	**2,188,550**	**$ 50.07**		

(1) As at December 31, 2024, there was $6 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 3 years (2023 – $5 million, 3 years).
(2) As at December 31, 2024, the weighted average remaining term of vested options was 4 years with an aggregate intrinsic value of $11 million (2023 – 5 years, $8 million).
(3) As at December 31, 2024, the FV of options that vested in the year was $2 million (2023 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2024 was $2 million (2023 – $2 million), which was included in “OM&G” on the Consolidated Statements of Income.

As at December 31, 2024, cash received from option exercises was $3 million (2023 – $6 million). The total intrinsic value of options exercised for the year ended December 31, 2024 was $1 million (2023 – $2 million). The range of exercise prices for the options outstanding as at December 31, 2024 was $39.93 to $60.03 (2023 – $32.35 to $60.03).

Share Unit Plans

The Company has DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on an average common share price at the end of the period.

Deferred Share Unit Plans

Under the Directors’ DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors’ fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera’s common shares, the Director’s DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant’s account is calculated by multiplying the number of DSUs in the participant’s account by Emera’s closing common share price on the date DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When short-term incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Unless otherwise determined by the Management Resources and Compensation Committee ("MRCC"), following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are made in cash.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2024 is presented in the following table:

	Employee DSU	Weighted Average Grant Date FV	Director DSU	Weighted Average Grant Date FV
Outstanding as at December 31, 2023	712,963	$ 42.29	729,058	$ 46.24
Granted including DRIP	86,417	45.20	134,795	48.98
Exercised	(10,292)	38.77	(34,997)	36.04
Outstanding and exercisable as at December 31, 2024	**789,088**	**$ 42.65**	**828,856**	**$ 47.12**

Compensation cost recognized for employee and director DSU's for the year ended December 31, 2024 was $13 million (2023 – $2 million cost recovery). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2024 were $4 million (2023 – $1 million tax expense). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2024 for employees was $43 million (2023 – $36 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2024 for directors was $45 million (2023 – $37 million). Cash payments made during the year ended December 31, 2024 associated with the DSU plan were $2 million (2023 – $3 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. Unless otherwise determined by the MRCC, PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2024 is presented in the following table:

	Employee PSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2023	743,365	$	55.13	$	41
Granted including DRIP	354,793		48.69		
Exercised	(253,136)		54.66		
Forfeited	(12,929)		52.53		
Outstanding as at December 31, 2024	**832,093**	**$**	**52.57**	**$**	**50**

Compensation cost recognized for the PSU plan for the year ended December 31, 2024 was $18 million (2023 – $11 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2024 were $5 million (2023 – $3 million). Cash payments made during the year ended December 31, 2024 associated with the PSU plan were $14 million (2023 – $19 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the plan. RSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. Unless otherwise determined by the MRCC, RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2024 is presented in the following table:

	Employee RSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2023	562,641	$	55.01	$	32
Granted including DRIP	287,976		48.65		
Exercised	(183,241)		54.66		
Forfeited	(14,228)		52.45		
Outstanding as at December 31, 2024	**653,148**	**$**	**52.36**	**$**	**41**

Compensation cost recognized for the RSU plan for the year ended December 31, 2024 was $15 million (2023 – $10 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2024 were $4 million (2023 – $3 million). Cash payments made during the year ended December 31, 2024 associated with the RSU plan were $10 million (2023– $10 million).

33. VARIABLE INTEREST ENTITIES

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. When the critical milestones were achieved, NLH was deemed the primary beneficiary of the asset for financial reporting purposes as it has authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a SIF, primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**December 31, 2024**		December 31, 2023	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 475**	**$ 6**	$ 489	$ 6

34. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 21, 2025, the date the financial statements were issued.