EMERA INCORPORATED

Consolidated Financial Statements

December 31, 2023 and 2022

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 26, 2024

“Scott Balfour”
President and Chief Executive Officer

“Gregory Blunden”
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, 2023 and 2022, 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, 2023 and 2022, 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 6 of the consolidated financial statements, the Company has $3.1 billion in regulatory assets and $1.8 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 $348 million and liabilities of $567 million, disclosed in note 15 to the consolidated financial statements, are measured at FV. The Company recognized $1,037 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 16 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.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance 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 26, 2024

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, 2023 and 2022, 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, 2023 and 2022, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2023, 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 6 of the consolidated financial statements, the Company has $3.1 billion in regulatory assets and $1.8 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, PP&E, operating revenues and expenses, income taxes, and depreciation expense.

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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

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	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 16 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 26, 2024

Emera Incorporated
Consolidated Statements of Income

For the millions of dollars (except per share amounts)	Year ended December 31 **2023**	2022
Operating revenues		
Regulated electric	**$ 5,746**	$ 5,473
Regulated gas	**1,489**	1,681
Non-regulated	**328**	434
Total operating revenues (note 5)	**7,563**	7,588
Operating expenses		
Regulated fuel for generation and purchased power	**1,881**	2,171
Regulated cost of natural gas	**527**	800
Operating, maintenance and general expenses ("OM&G")	**1,879**	1,596
Provincial, state, and municipal taxes	**433**	367
Depreciation and amortization	**1,049**	952
GBPC Impairment charge (note 22)	**-**	73
Total operating expenses	**5,769**	5,959
Income from operations	**1,794**	1,629
Income from equity investments (note 7)	**146**	129
Other income, net (note 8)	**158**	145
Interest expense, net (note 9)	**925**	709
Income before provision for income taxes	**1,173**	1,194
Income tax expense (note 10)	**128**	185
Net income	**1,045**	1,009
Non-controlling interest in subsidiaries	**1**	1
Preferred stock dividends	**66**	63
Net income attributable to common shareholders	**$ 978**	$ 945
Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	**274**	266
Diluted	**274**	266
Earnings per common share (note 12)		
Basic	**$ 3.57**	$ 3.56
Diluted	**$ 3.57**	$ 3.55
Dividends per common share declared	**$ 2.7875**	$ 2.6775

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 **2023**	 2022
Net income	**$ 1,045**	$ 1,009
Other comprehensive (loss) income, net of tax		
Foreign currency translation adjustment (1)	**(270)**	629
Unrealized gains (losses) on net investment hedges (2) (3)	**38**	(97)
Cash flow hedges – reclassification adjustment for gains included in income (4)	**(2)**	(2)
Unrealized losses on available-for-sale investment	**-**	(1)
Net change in unrecognized pension and post-retirement benefit obligation (5)	**(39)**	24
Other comprehensive (loss) income (6)	**(273)**	553
Comprehensive income	**772**	1,562
Comprehensive income attributable to non-controlling interest	**1**	1
Comprehensive Income of Emera Incorporated	**$ 771**	$ 1,561

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

1) Net of tax recovery of $7 million for the year ended December 31, 2023 (2022 – $7 million expense).
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, 2023 (2022 – $6 million recovery).
4) Net of tax expense of nil for the year ended December 31, 2023 (2022 – $1 million recovery).
5) Net of tax expense of $1 million for the year ended December 31, 2023 (2022 – $1 million expense).
6) Net of tax recovery of $6 million for the year ended December 31, 2023 (2022 – $1 million expense).

Emera Incorporated
Consolidated Balance Sheets

As at millions of dollars		**December 31 2023**		December 31 2022
Assets				
Current assets				
Cash and cash equivalents	**$**	**567**	$	310
Restricted cash (note 32)		**21**		22
Inventory (note 14)		**790**		769
Derivative instruments (notes 15 and 16)		**174**		296
Regulatory assets (note 6)		**339**		602
Receivables and other current assets (note 18)		**1,817**		2,897
		3,708		4,896
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $9,994 and $9,574, respectively (note 20)		**24,376**		22,996
Other assets				
Deferred income taxes (note 10)		**208**		237
Derivative instruments (notes 15 and 16)		**66**		100
Regulatory assets (note 6)		**2,766**		3,018
Net investment in direct finance and sales type leases (note 19)		**621**		604
Investments subject to significant influence (note 7)		**1,402**		1,418
Goodwill (note 22)		**5,871**		6,012
Other long-term assets (note 32)		**462**		461
		11,396		11,850
Total assets	**$**	**39,480**	$	39,742
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	**$**	**1,433**	$	2,726
Current portion of long-term debt (note 25)		**676**		574
Accounts payable		**1,454**		2,025
Derivative instruments (notes 15 and 16)		**386**		888
Regulatory liabilities (note 6)		**168**		495
Other current liabilities (note 24)		**427**		579
		4,544		7,287
Long-term liabilities				
Long-term debt (note 25)		**17,689**		15,744
Deferred income taxes (note 10)		**2,352**		2,196
Derivative instruments (notes 15 and 16)		**118**		190
Regulatory liabilities (note 6)		**1,604**		1,778
Pension and post-retirement liabilities (note 21)		**265**		281
Other long-term liabilities (note 7 and 26)		**820**		825
		22,848		21,014
Equity				
Common stock (note 11)		**8,462**		7,762
Cumulative preferred stock (note 28)		**1,422**		1,422
Contributed surplus		**82**		81
Accumulated other comprehensive income ("AOCI') (note 13)		**305**		578
Retained earnings		**1,803**		1,584
Total Emera Incorporated equity		**12,074**		11,427
Non-controlling interest in subsidiaries (note 29)		**14**		14
Total equity		**12,088**		11,441
Total liabilities and equity	**$**	**39,480**	$	39,742

Commitments and contingencies (note 27)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of dollars		Year ended December 31 **2023**		2022
Operating activities				
Net income	**$**	**1,045**	$	1,009
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization		**1,060**		959
Income from equity investments, net of dividends		**(22)**		(61)
Allowance for funds used during construction ("AFUDC") – equity		**(38)**		(52)
Deferred income taxes, net		**97**		152
Net change in pension and post-retirement liabilities		**(68)**		(48)
NSPI Fuel adjustment mechanism ("FAM")		**(88)**		(162)
Net change in Fair Value ("FV") of derivative instruments		**(666)**		206
Net change in regulatory assets and liabilities		**554**		(471)
Net change in capitalized transportation capacity		**434**		(445)
GBPC impairment charge		**-**		73
Other operating activities, net		**28**		(13)
Changes in non-cash working capital (note 30)		**(95)**		(234)
Net cash provided by operating activities		**2,241**		913
Investing activities				
Additions to PP&E		**(2,937)**		(2,596)
Other investing activities		**20**		27
Net cash used in investing activities		**(2,917)**		(2,569)
Financing activities				
Change in short-term debt, net		**(66)**		1,028
Proceeds from short-term debt with maturities greater than 90 days		**548**		544
Repayment of short-term debt with maturities greater than 90 days		**(1,086)**		(680)
Proceeds from long-term debt, net of issuance costs		**1,932**		784
Retirement of long-term debt		**(151)**		(367)
Net (repayments) proceeds under committed credit facilities		**(96)**		511
Issuance of common stock, net of issuance costs		**424**		277
Dividends on common stock		**(488)**		(472)
Dividends on preferred stock		**(66)**		(63)
Other financing activities		**(12)**		(7)
Net cash provided by financing activities		**939**		1,555
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**(7)**		16
Net increase (decrease) in cash, cash equivalents, and restricted cash		**256**		(85)
Cash, cash equivalents, and restricted cash, beginning of year		**332**		417
Cash, cash equivalents, and restricted cash, end of year	**$**	**588**	$	332
Cash, cash equivalents, and restricted cash consists of:				
Cash	**$**	**559**	$	302
Short-term investments		**8**		8
Restricted cash		**21**		22
Cash, cash equivalents, and restricted cash	**$**	**588**	$	332

Supplementary Information to Consolidated Statements of Cash Flows (note 30)

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	Non-Controlling Interest	Total Equity
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 28)	**-**	**-**	**-**	**-**	**(66)**	**-**	**(66)**
Dividends declared on common stock ($2.7875/share)	**-**	**-**	**-**	**-**	**(759)**	**-**	**(759)**
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	**397**	**-**	**-**	**-**	**-**	**-**	**397**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	**272**	**-**	**-**	**-**	**-**	**-**	**272**
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	**31**	**-**	**1**	**-**	**-**	**-**	**32**
Other	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Balance, December 31, 2023	**$ 8,462**	**$ 1,422**	**$ 82**	**$ 305**	**$ 1,803**	**$ 14**	**$ 12,088**
Balance, December 31, 2021	$ 7,242	$ 1,422	$ 79	$ 25	$ 1,348	$ 34	$ 10,150
Net income of Emera Inc.	-	-	-	-	1,008	1	1,009
Other comprehensive income, net of tax expense of $1 million	-	-	-	553	-	-	553
Dividends declared on preferred stock (note 28)	-	-	-	-	(63)	-	(63)
Dividends declared on common stock ($2.6775/share)	-	-	-	-	(709)	-	(709)
Issued under the ATM, net of after-tax issuance costs	248	-	-	-	-	-	248
Issued under the DRIP, net of discount	238	-	-	-	-	-	238
Senior management stock options exercised and ECSPP	34	-	2	-	-	-	36
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	-	-	-	-	-	(20)	(20)
Other	-	-	-	-	-	(1)	(1)
Balance, December 31, 2022	$ 7,762	$ 1,422	$ 81	$ 578	$ 1,584	$ 14	$ 11,441

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

Emera Incorporated
Notes to the Consolidated Financial Statements
As at December 31, 2023 and 2022

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

At December 31, 2023, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 840,000 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 549,000 customers; and
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL"), consisting of two transmission investments related to an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, developed by Nalcor Energy. ENL's two investments are:
        - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion transmission project, including AFUDC; and
        - a 31 per cent equity interest in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador.

- Gas Utilities and Infrastructure, which includes:
    - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 490,000 customers across Florida. Effective January 1, 2023, Peoples Gas System ceased to be a division of Tampa Electric Company and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.;
    - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 540,000 customers in New Mexico;
    - 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 border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy"), 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 United States.

- 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 134,000 customers;
    - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 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 reportable segment includes investments in energy-related non-regulated companies which include:
    - 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") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
    - Block Energy LLC (previously Emera Technologies LLC), a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers;
    - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; 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 32.

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 6.

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 Other Comprehensive Income ("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 amount, including goodwill. 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 the utility industry. 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, 2023, $5,868 million of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further details, refer to note 22.

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, ENL 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, ENL 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 10.

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 has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

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 or investing 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 "Operating, maintenance and general" 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.

As at December 31, 2023, there are no indications of impairment of Emera's long-lived assets. No impairment charges related to long-lived assets were recognized in 2023 or 2022.

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 2023 or 2022.

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 2023 or 2022.

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 "Property, plant and equipment" 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. 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 21.

2. 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.

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, and interim periods within annual reporting periods beginning after December 15, 2025. 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.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued 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 will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

3. DISPOSITIONS

On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Domlec for proceeds which approximated its carrying value. Domlec was included in the Company's Other Electric reportable segment up to its date of sale. The sale did not have a material impact on earnings.

4. 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.

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**
Non-controlling interest 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.

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, 2022							
Operating revenues from external customers (1)	$ 3,280	$ 1,675	$ 1,697	$ 518	$ 418	$ -	$ **7,588**
Inter-segment revenues (1)	7	-	7	-	22	(36)	**-**
Total operating revenues	3,287	1,675	1,704	518	440	(36)	**7,588**
Regulated fuel for generation and purchased power	1,086	803	-	290	-	(8)	**2,171**
Regulated cost of natural gas	-	-	800	-	-	-	**800**
OM&G	625	338	365	123	156	(11)	**1,596**
Provincial, state and municipal taxes	235	43	83	3	3	-	**367**
Depreciation and amortization	507	259	118	61	7	-	**952**
Income from equity investments	-	87	21	4	17	-	**129**
Other income (expenses), net	68	24	13	-	23	17	**145**
Interest expense, net (2)	185	136	81	19	288	-	**709**
GBPC impairment charge	-	-	-	73	-	-	**73**
Income tax expense (recovery)	121	(8)	70	-	2	-	**185**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	63	-	**63**
Net income (loss) attributable to common shareholders	$ 596	$ 215	$ 221	$ (48)	$ (39)	$ -	$ **945**
Capital expenditures	$ 1,425	$ 507	$ 574	$ 63	$ 6	$ -	$ **2,575**
As at December 31, 2022							
Total assets	$ 21,053	$ 8,223	$ 7,737	$ 1,337	$ 2,835	$ (1,443)	$ **39,742**
Investments subject to significant influence	$ -	$ 1,241	$ 128	$ 49	$ -	$ -	$ **1,418**
Goodwill	$ 4,739	$ -	$ 1,270	$ -	$ 3	$ -	$ **6,012**

(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 $13 million for the year ended December 31, 2022, between the 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 **2023**	2022
United States	**5,310**	$ 5,346
Canada	**1,727**	1,725
Barbados	**389**	384
The Bahamas	**137**	122
Dominica	**-**	11
	$ 7,563	$ 7,588

Property Plant and Equipment:

As at millions of dollars	**December 31 2023**	December 31 2022
United States	**$ 18,588**	$ 17,382
Canada	**4,878**	4,689
Barbados	**576**	583
The Bahamas	**334**	342
	$ 24,376	$ 22,996

5. REVENUE

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

millions of dollars	Electric			Gas	Other		
	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-Segment Eliminations	Total
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 Revenue							
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**
For the year ended December 31, 2022							
Regulated Revenue							
Residential	$ 1,799	$ 834	$ 184	$ 800	$ -	$ -	**$** 3,617
Commercial	869	427	282	461	-	-	2,039
Industrial	230	353	32	83	-	(7)	691
Other electric	398	28	6	-	-	-	432
Regulatory deferrals	(27)	-	6	-	-	-	(21)
Other (1)	18	33	8	283	-	(7)	335
Finance income (2)(3)	-	-	-	61	-	-	61
Regulated revenue	$ 3,287	$ 1,675	$ 518	$ 1,688	$ -	$ (14)	7,154
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	143	-	143
Other non-regulated operating revenue	-	-	-	16	16	(10)	22
Mark-to-market (3)	-	-	-	-	281	(12)	269
Non-regulated revenue	$ -	$ -	$ -	$ 16	$ 440	$ (22)	434
Total operating revenues	$ 3,287	$ 1,675	$ 518	$ 1,704	$ 440	$ (36)	$ 7,588

(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, 2023, the aggregate amount of the transaction price allocated to remaining performance obligations was $488 million (2022 – $450 million). This amount includes $134 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 2043.

6. 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 2023**		December 31 2022
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,233**	$	1,166
TEC capital cost recovery for early retired assets		**671**		674
NSPI FAM		**395**		307
Pension and post-retirement medical plan		**364**		369
Cost recovery clauses		**151**		707
Deferrals related to derivative instruments		**88**		30
Storm cost recovery clauses		**52**		138
Environmental remediations		**26**		27
Stranded cost recovery		**25**		27
NMGC winter event gas cost recovery		**-**		69
Other		**100**		106
	$	**3,105**	$	3,620
Current	**$**	**339**	$	602
Long-term		**2,766**		3,018
Total regulatory assets	**$**	**3,105**	$	3,620
Regulatory liabilities				
Accumulated reserve – COR		**849**		895
Deferred income tax regulatory liabilities		**830**		877
Cost recovery clauses		**32**		70
BLPC Self-insurance fund ("SIF") (note 32)		**29**		30
Deferrals related to derivative instruments		**17**		230
NMGC gas hedge settlements (note 18)		**-**		162
Other		**15**		9
	$	**1,772**	$	2,273
Current	**$**	**168**	$	495
Long-term		**1,604**		1,778
Total regulatory liabilities	**$**	**1,772**	$	2,273

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

This regulatory asset is related to the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were 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. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021. For further information, refer to "Big Bend Modernization Project" in the TEC section below.

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.

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 NMGC. It is included in rate base and earns a rate of return as permitted by the FPSC and NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

Cost Recovery Clauses

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

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.

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 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. In 2022, TEC and PGS were impacted by Hurricane Ian. For further information, refer to "TEC Storm Reserve" in the Florida Electric Utility section below.

NSPI Storm Rider:
NSPI has a UARB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the UARB for recovery of costs if major storm restoration expenses exceed approximately $10 million in a given year.

GBPC Storm Restoration:
This asset represents storm restoration costs incurred by GBPC. GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are not covered by commercial insurance.

In January 2020, the Grand Bahama Port Authority ("GBPA") approved recovery of $15 million USD of 2019 costs related to Hurricane Dorian, over a five-year period from 2021 through 2025.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. For further information, refer to "Storm Restoration Costs – Hurricane Matthew" in the GBPC section below.

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.

NMGC Winter Event Gas Cost Recovery

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause ("PGAC"). On June 15, 2021, the NMPRC approved recovery of $108 million USD and related borrowing costs in customer rates over a period of 30 months from July 1, 2021, to December 31, 2023.

Accumulated Reserve – COR

This regulatory liability represents the non-ARO COR reserve in TEC, PGS, NMGC and NSPI. 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.

NMGC Gas Hedge Settlements

This regulatory liability represents regulatory deferral of gas options exercised above strike price but settled subsequent to the period end. The value from cash settlement of these options flows to customers via the PGAC.

Other Regulatory Assets and Liabilities

Comprised of regulatory assets and liabilities that are not individually significant.

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 2023 and 2022 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 (2022 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

Base Rates:
On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024.

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 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.

The mid-course fuel adjustment requested by TEC on January 19, 2022, was approved on March 1, 2022. The rate increase, effective with the first billing cycle in April 2022, covered higher fuel and capacity costs of $169 million USD, and was spread over customer bills from April 1, 2022 through December 2022.

Big Bend Modernization Project:
TEC invested $876 million USD, including $91 million USD of AFUDC, between 2018 and 2022 to modernize the Big Bend Power Station. The modernization project repowered Big Bend Unit 1 with natural gas combined-cycle technology and eliminated coal as this unit's fuel. As part of the modernization project, TEC in 2020 retired the Unit 1 components that would not be used in the modernized plant and did the same for Big Bend Unit 2 in 2021. TEC retired Big Bend Unit 3 in 2023 as it was in the best interests of the customers from an economic, environmental risk and operational perspective. On December 31, 2021, the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, of $636 million USD and $267 million USD in accumulated depreciation were reclassified to a regulatory asset on the balance sheet.

TEC's 2021 settlement agreement provides for cost recovery of the Big Bend Modernization project in two phases. The first phase was a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs were recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, which are spread over 15 years, effective January 1, 2022. This recovery mechanism was authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

Storm Reserve:
In September 2022, TEC was impacted by Hurricane Ian, with $119 million USD of restoration costs charged against TEC's FPSC approved storm reserve. Total restoration costs charged to the storm reserve exceeded the reserve balance and have been deferred as a regulatory asset for future recovery.

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. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings.

Storm Protection Cost Recovery Clause and Settlement Agreement:
The Storm Protection Plan ("SPP") 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. A settlement agreement was approved on August 10, 2020, and TEC's cost recovery began in January 2021. The current approved plan addressed the years 2023, 2024 and 2025 and was approved by the FPSC on October 4, 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 2023 and 2022 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.

General Rate Application ("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:
For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan with no fuel rate adjustments related to the under-recovery of fuel and fuel-related costs in the period.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding FAM balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024.

Storm Rider:
The storm rider was effective as of the 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. Total major storm restoration expense for 2023 was $31 million, of which $21 million was deferred to the storm rider.

Hurricane Fiona:
On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval.

Maritime Link:
The Maritime Link is a $1.8 billion (including AFUDC) transmission project including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018 and NSPI started interim assessment payments to NSPML at that time.

Any difference between the amounts recovered from customers through rates and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program:
As of 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 of Nova Scotia 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.

Nalcor's Nova Scotia Block ("NS Block") delivery obligations commenced on August 15, 2021 and delivery will continue over the next 35 years pursuant to the agreements.

In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion less $9 million of costs ($7 million after-tax) that would not have otherwise been recoverable if incurred by NSPI.

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 relating 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. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are 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.

On December 21, 2023, NSPML received approval to collect up to $164 million (2023 – $164 million) from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of up to $4 million a month, as discussed above.

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 2023 and 2022 was 8.9 per cent to 11.0 per cent with a 9.9 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.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

Fuel Recovery:
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its 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 2023 and 2022 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 to become effective Q4 2024. NMGC requested $49 million USD in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent.

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 2020, for the four-year period ending December 2024.

Integrity Management Programs ("IMP") Regulatory Asset:
A portion of NMGC's annual spending on infrastructure is for IMP, or the replacement and update of legacy systems. These programs are driven both by NMGC integrity management plans and federal and state mandates. In December 2020, NMGC received approval through its rate case to defer costs through an IMP regulatory asset for certain of its IMP capital investments occurring between January 1, 2022 and December 31, 2023 and petitioned recovery of the regulatory asset in its rate case filed on December 13, 2021. On November 30, 2022, the NMPRC issued a Final Order that included approval of recovery of the IMP regulatory asset.

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 United States. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy North America Canada Partnership. 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 2023 and 2022.

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 related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 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.

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 Program ("CETP"):
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 CETP (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 CETP.

Fuel Hedging:
On October 21, 2021, the FTC approved BLPC's application to implement a fuel hedging program which will be incorporated into the calculation of the fuel clause adjustment. On November 10, 2021, BLPC requested the FTC review the required 50/50 cost sharing arrangement between BLPC and customers in relation to the hedging administrative costs, or any gains and losses associated with the hedging program.

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 8.32 per cent for 2023 (2022 – 8.23 per cent).

Base Rates:
There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. On January 14, 2022, the GBPA issued its decision on GBPC's application for rate review that was filed with the GBPA on September 23, 2021. The decision, which became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The rates include a regulatory ROE of 12.84 per cent.

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.

Effective November 1, 2022, GBPC's fuel pass through charge was increased due to an increase in global oil prices impacting the unhedged fuel cost. In 2023, the fuel pass through charge was adjusted monthly, in-line with actual fuel costs.

Storm Restoration Costs – Hurricane Matthew:
As part of the recovery of costs incurred as a result of Hurricane Matthew, in 2016, the GBPA approved a fixed per kWh fuel charge and allowed the difference between this and the actual cost of fuel to be applied to the Hurricane Matthew regulatory asset. As part of its decision on GBPC's application for rate review, issued January 14, 2022, and effective April 1, 2022, the GBPA approved the continued amortization of the remaining regulatory asset over the three year period ending December 31, 2024.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value As at December 31 2023	2022	Equity Income For the year ended December 31 2023	2022	Percentage of Ownership 2023
LIL (1)	**$ 747**	$ 740	**$ 63**	$ 58	**31.0**
NSPML	**489**	501	**46**	29	**100.0**
M&NP (2)	**118**	128	**21**	21	**12.9**
Lucelec (2)	**48**	49	**4**	4	**19.5**
Bear Swamp (3)	**-**	-	**12**	17	**50.0**
	$ 1,402	$ 1,418	**$ 146**	$ 129	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.5 per cent of the total units issued. Percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.
(2) 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.
(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 $81 million (2022 – $95 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $10 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 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of dollars	December 31 2023	2022
Balance Sheets		
Current assets	**$ 21**	$ 17
PP&E	**1,473**	1,517
Regulatory assets	**272**	265
Non-current assets	**29**	29
Total assets	**$ 1,795**	$ 1,828
Current liabilities	**$ 48**	$ 48
Long-term debt (1)	**1,109**	1,149
Non-current liabilities	**149**	130
Equity	**489**	501
Total liabilities and equity	**$ 1,795**	$ 1,828

(1) The project debt has been guaranteed by the Government of Canada.

8. OTHER INCOME, NET

For the millions of dollars	Year ended December 31 2023	2022
Interest income	**$ 43**	$ 25
AFUDC	**38**	52
Pension non-current service cost recovery	**35**	24
FX gains (losses)	**20**	(26)
TECO Guatemala Holdings award (1)	**-**	63
Other	**22**	7
	$ 158	$ 145

(1) On December 15, 2022, a payment of $63 million was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment in TGH, a wholly-owned subsidiary of TECO Energy.

9. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2023**	2022
Interest on debt	**$ 954**	$ 727
Allowance for borrowed funds used during construction	**(16)**	(21)
Other	**(13)**	3
	$ 925	$ 709

10. 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	**2023**	2022
Income before provision for income taxes	**$ 1,173**	$ 1,194
Statutory income tax rate	**29.0%**	29.0%
Income taxes, at statutory income tax rate	**340**	346
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(72)**	(70)
Tax credits	**(53)**	(18)
Foreign tax rate variance	**(36)**	(44)
Amortization of deferred income tax regulatory liabilities	**(33)**	(33)
Tax effect of equity earnings	**(15)**	(10)
GBPC impairment charge	**-**	21
Other	**(3)**	(7)
Income tax expense	**$ 128**	$ 185
Effective income tax rate	**11%**	15%

On August 16, 2022, the United States Inflation Reduction Act (“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, 2023, the Company has recorded a $30 million (2022 - $9 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	**2023**	2022
Current income taxes		
Canada	**$ 26**	$ 25
United States	**5**	8
Deferred income taxes		
Canada	**93**	122
United States	**128**	252
Investment tax credits		
United States	**(29)**	(7)
Operating loss carryforwards		
Canada	**(93)**	(94)
United States	**(2)**	(121)
Income tax expense	**$ 128**	$ 185

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		**2023**		2022
Canada	**$**	**171**	$	173
United States		**964**		1,063
Other		**38**		(42)
Income before provision for income taxes	**$**	**1,173**	$	1,194

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

millions of dollars		**2023**		2022
Deferred income tax assets:				
Tax loss carryforwards	**$**	**1,195**	$	1,207
Tax credit carryforwards		**454**		415
Derivative instruments		**205**		45
Regulatory liabilities		**175**		264
Other		**372**		341
Total deferred income tax assets before valuation allowance		**2,401**		2,272
Valuation allowance		**(363)**		(312)
Total deferred income tax assets after valuation allowance	**$**	**2,038**	$	1,960
Deferred income tax (liabilities):				
PP&E	**$**	**(3,223)**	$	(2,981)
Derivative instruments		**(235)**		(125)
Investments subject to significant influence		**(216)**		(181)
Regulatory assets		**(196)**		(310)
Other		**(312)**		(322)
Total deferred income tax liabilities	**$**	**(4,182)**	$	(3,919)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	**$**	**208**	$	237
Long-term deferred income tax liabilities		**(2,352)**		(2,196)
Net deferred income tax liabilities	**$**	**(2,144)**	$	(1,959)

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 $363 million has been recorded as at December 31, 2023 (2022 – $312 million) related to the loss carryforwards, long-term debt and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, as at December 31, 2023, $4.7 billion (2022 – $3.8 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, 2023 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 2,914	$ (1,164)	$ 1,750	2026 - 2043
Capital loss	73	(73)	-	Indefinite
United States				
Federal NOL	$ 1,360	$ (1)	$ 1,359	2036 - Indefinite
State NOL	1,003	(1)	1,002	2026 - Indefinite
Tax credit	454	(3)	451	2025 - 2043
Other				
NOL	$ 81	$ (28)	$ 53	2024 - 2030

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

millions of dollars	**2023**	2022
Balance, January 1	**$ 33**	$ 28
Increases due to tax positions related to current year	**5**	5
Increases due to tax positions related to a prior year	**1**	2
Decreases due to tax positions related to a prior year	**(2)**	(2)
Balance, December 31	**$ 37**	$ 33

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, 2023 was $37 million (2022 – $33 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $9 million (2022 – $7 million) with $2 million interest expense recognized in the Consolidated Statements of Income (2022 – $1 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.

During 2022, the CRA issued notices of reassessment to NSPI for the 2013 through 2016 taxation years. 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 (2022 – $126 million), including interest. NSPI has prepaid $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, 2023, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

11. COMMON STOCK

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

		2023		2022
Issued and outstanding:	**millions of shares**	**millions of dollars**	millions of shares	millions of dollars
Balance, January 1	**269.95**	**$ 7,762**	261.07	$ 7,242
Issuance of common stock under ATM program (1)(2)	**8.29**	**397**	4.07	248
Issued under the DRIP, net of discounts	**5.26**	**272**	4.21	238
Senior management stock options exercised and Employee Share Purchase Plan	**0.62**	**31**	0.60	34
Balance, December 31	**284.12**	**$ 8,462**	269.95	$ 7,762

(1) For the year ended December 31, 2022, a total of 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).
(2) 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).

As at December 31, 2023, the following common shares were reserved for issuance: 6 million (2022 – 6 million) under the senior management stock option plan, 2 million (2022 – 2.7 million) under the employee common share purchase plan and 18 million (2022 – 10 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, 2023, Emera was in compliance with this requirement.

ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. This ATM Program is expected to remain in effect until November 4, 2025.

12. 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 **2023**	2022
Numerator		
Net income attributable to common shareholders	**$ 977.7**	$ 945.1
Diluted numerator	**977.7**	945.1
Denominator		
Weighted average shares of common stock outstanding – basic	**273.6**	265.5
Stock-based compensation	**0.2**	0.4
Weighted average shares of common stock outstanding – diluted	**273.8**	265.9
Earnings per common share		
Basic	**$ 3.57**	$ 3.56
Diluted	**$ 3.57**	$ 3.55

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI are as follows:

millions of dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	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, 2023						
Balance, January 1, 2023	**$ 639**	**$ (62)**	**$ 16**	**$ (2)**	**$ (13)**	**$ 578**
Other comprehensive (loss) income before reclassifications	**(270)**	**38**	**-**	**-**	**-**	**(232)**
Amounts reclassified from AOCI	**-**	**-**	**(2)**	**-**	**(39)**	**(41)**
Net current period other comprehensive (loss) income	**(270)**	**38**	**(2)**	**-**	**(39)**	**(273)**
Balance, December 31, 2023	**$ 369**	**$ (24)**	**$ 14**	**$ (2)**	**$ (52)**	**$ 305**
For the year ended December 31, 2022						
Balance, January 1, 2022	$ 10	$ 35	$ 18	$ (1)	$ (37)	$ 25
Other comprehensive income (loss) before reclassifications	629	(97)	-	(1)	-	531
Amounts reclassified from AOCI	-	-	(2)	-	24	22
Net current period other comprehensive income (loss)	629	(97)	(2)	(1)	24	553
Balance, December 31, 2022	$ 639	$ (62)	$ 16	$ (2)	$ (13)	$ 578

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 **2023**	2022
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	**$ -**	$ 10
Past service costs	Other income, net	**2**	-
Amounts reclassified into obligations	Pension and post-retirement benefits	**(40)**	15
Total before tax		**(38)**	25
Income tax expense		**(1)**	(1)
Total net of tax		**$ (39)**	$ 24
Total reclassifications out of AOCI, net of tax, for the period		**$ (41)**	$ 22

14. INVENTORY

As at millions of dollars	**December 31 2023**	December 31 2022
Fuel	**$ 382**	$ 404
Materials	**408**	365
Total	**$ 790**	$ 769

15. 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 2023**	December 31 2022	**December 31 2023**	December 31 2022
Regulatory deferral:				
Commodity swaps and forwards	**$ 16**	$ 186	**$ 76**	$ 42
FX forwards	**3**	18	**3**	1
Physical natural gas purchases and sales	**-**	52	**-**	-
	19	256	**79**	43
HFT derivatives:				
Power swaps and physical contracts	**29**	89	**36**	77
Natural gas swaps, futures, forwards, physical contracts	**319**	340	**531**	1,224
	348	429	**567**	1,301
Other derivatives:				
Equity derivatives	**4**	-	**-**	5
FX forwards	**18**	5	**7**	23
	22	5	**7**	28
Total gross current derivatives	**389**	690	**653**	1,372
Impact of master netting agreements:				
Regulatory deferral	**(3)**	(18)	**(3)**	(18)
HFT derivatives	**(146)**	(276)	**(146)**	(276)
Total impact of master netting agreements	**(149)**	(294)	**(149)**	(294)
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078
Current (1)	**174**	296	**386**	888
Long-term (1)	**66**	100	**118**	190
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078

(1) 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.

The amounts related to cash flow hedges recorded in AOCI consisted of the following:

For the millions of dollars	Year ended December 31 **2023** **Interest rate hedge**	 2022 Interest rate hedge
Realized gain in interest expense, net	**$ 2**	$ 2
Total gains in net income	**$ 2**	$ 2

As at millions of dollars	**December 31 2023** **Interest rate hedge**	December 31 2022 Interest rate hedge
Total unrealized gain in AOCI – effective portion, net of tax	**$ 14**	$ 16

The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months.

Regulatory Deferral

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

millions of dollars	**Physical natural gas purchases**	**Commodity swaps and forwards**	**FX forwards**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the year ended December 31			**2023**			2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (109)**	**$ (3)**	$ -	$ (69)	$ 1
Unrealized gain (loss) in regulatory liabilities	**(3)**	**(73)**	**-**	28	343	16
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	48	-
Realized (gain) loss in regulatory liabilities	**-**	**2**	**-**	-	(41)	-
Realized (gain) loss in inventory (1)	**-**	**4**	**(10)**	-	(121)	1
Realized (gain) in regulated fuel for generation and purchased power (2)	**(49)**	**(9)**	**(4)**	(64)	(146)	**-**
Other	**-**	**(14)**	**-**	-	-	-
Total change in derivative instruments	**$ (52)**	**$ (204)**	**$ (17)**	$ (36)	$ 14	$ 18

(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, 2023, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions		2024		2025-2026
Physical natural gas purchases:				
Natural gas (MMBtu)		7		6
Commodity swaps and forwards purchases:				
Natural gas (MMBtu)		16		10
Power (MWh)		1		1
Coal (metric tonnes)		1		-
FX swaps and forwards:				
FX contracts (millions of USD)	$	241	$	70
Weighted average rate		1.3155		1.3197
% of USD requirements		63%		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 **2023**		2022
Power swaps and physical contracts in non-regulated operating revenues	**$**	**(6)**	$	17
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues		**1,043**		47
Total gains in net income	**$**	**1,037**	$	64

As at December 31, 2023, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2024	2025	2026	2027	2028 and thereafter
Natural gas purchases (Mmbtu)	296	80	50	38	30
Natural gas sales (Mmbtu)	338	86	16	6	4
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at December 31, 2023, the Company had equity derivatives in place to manage the 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 2024. The FX forwards have a combined notional amount of $508 million USD and expire in 2023, 2024 and 2025.

For the millions of dollars				Year ended December 31 **2023**				2022
		FX Forwards		**Equity Derivatives**		FX Forwards		Equity Derivatives
Unrealized gain (loss) in OM&G	**$**	**-**	**$**	**4**	$	**-**	$	(5)
Unrealized gain (loss) in other income, net		**28**		**-**		(18)		-
Realized loss in OM&G		**-**		**(13)**		-		(17)
Realized loss in other income, net		**(11)**		**-**		(6)		-
Total gains (losses) in net income	**$**	**17**	**$**	**(9)**	$	(24)	$	(22)

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, 2023, the maximum exposure the Company had to credit risk was $1.2 billion (2022 – $1.9 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, 2023 was $310 million (2022 – $386 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, 2023, the Company had $142 million (2022 – $131 million) in financial assets, considered to be past due, which have been outstanding for an average 64 days. The FV of these financial assets was $127 million (2022 – $114 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, 2023**		December 31, 2022	
	millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net				
Regulated utilities:				
Residential	**$ 476**	**31%**	$ 455	19%
Commercial	**194**	**13%**	192	8%
Industrial	**84**	**5%**	121	5%
Other	**103**	**7%**	122	5%
Cash collateral	**94**	**6%**	-	0%
	951	**62%**	890	37%
Trading group:				
Credit rating of A- or above	**47**	**3%**	125	5%
Credit rating of BBB- to BBB+	**33**	**2%**	75	3%
Not rated	**108**	**7%**	307	13%
	188	**12%**	507	21%
Other accounts receivable	**151**	**10%**	585	25%
	1,290	**84%**	1,982	83%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**138**	**9%**	202	9%
Credit rating of BBB- to BBB+	**7**	**1%**	8	0%
Not rated	**95**	**6%**	186	8%
	240	**16%**	396	17%
	$ 1,530	**100%**	$ 2,378	100%

Cash Collateral

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

As at millions of dollars	**December 31 2023**	December 31 2022
Cash collateral provided to others	**$ 101**	$ 224
Cash collateral received from others	**$ 22**	$ 112

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, 2023, the total FV of derivatives in a liability position was $504 million (December 31, 2022 – $1,078 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.

16. 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, 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)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 120	$ 48	$ -	$ 168
FX forwards	-	18	-	18
Physical natural gas purchases and sales	-	-	52	52
	120	66	52	238
HFT derivatives:				
Power swaps and physical contracts	9	31	4	44
Natural gas swaps, futures, forwards, physical contracts and related transportation	3	72	34	109
	12	103	38	153
Other derivatives:				
FX forwards	-	5	-	5
Total assets	132	174	90	396
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	9	-	24
FX forwards	-	1	-	1
	15	10	-	25
HFT derivatives:				
Power swaps and physical contracts	2	28	1	31
Natural gas swaps, futures, forwards and physical contracts	51	118	825	994
	53	146	826	1,025
Other derivatives:				
FX forwards	-	23	-	23
Equity derivatives	5	-	-	5
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

The change in the FV of the Level 3 financial assets for the year ended December 31, 2023 was as follows:

	Regulatory Deferral	***HFT Derivatives***		
millions of dollars	**Physical natural gas purchases**	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 52**	**$ 4**	**$ 34**	**$ 90**
Realized gains (losses) included in fuel for generation and purchased power	**(49)**	**-**	**-**	**(49)**
Unrealized gains (losses) included in regulatory assets and liabilities	**(3)**	**-**	**-**	**(3)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(4)**	**-**	**(4)**
Balance, December 31, 2023	**$ -**	**$ -**	**$ 34**	**$ 34**

The change in the FV of the Level 3 financial liabilities for the year ended December 31, 2023 was as follows:

	HFT Derivatives		
millions of dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 1**	**$ 825**	**$ 826**
Total realized and unrealized gains included in non-regulated operating revenues	**(1)**	**(460)**	**(461)**
Balance, December 31, 2023	**$ -**	**$ 365**	**$ 365**

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, 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**				
As at December 31, 2022						
Regulatory deferral – Physical natural gas purchases	$ 52	$ -	Third-party pricing	$5.79	$31.85	$12.27
HFT derivatives – Power swaps and physical contracts	4	1	Third-party pricing	$43.24	$269.10	$138.79
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	34	825	Third-party pricing	$2.45	$33.88	$12.01
Total	$ 90	$ 826				
Net liability		$ 736				

(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, 2023	**$ 18,365**	**$ 16,621**	**$ -**	**$ 16,363**	**$ 258**	**$ 16,621**
December 31, 2022	$ 16,318	$ 14,670	$ -	$ 14,284	$ 386	$ 14,670

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, 2023, the FV of the Hybrid Notes was $1.2 billion (2022 – $1.1 billion). An after-tax foreign currency gain of $38 million was recorded in AOCI for the year ended December 31, 2023 (2022 – $97 million after-tax loss).

17. 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 $163 million for the year ended December 31, 2023 (2022 – $157 million). 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 $14 million for the year ended December 31, 2023 (2022 – $9 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, 2023 and at December 31, 2022.

18. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars		**December 31 2023**		December 31 2022
Customer accounts receivable – billed	**$**	**805**	$	1,096
Capitalized transportation capacity (1)		**358**		781
Customer accounts receivable – unbilled		**363**		424
Prepaid expenses		**105**		82
Income tax receivable		**10**		9
Allowance for credit losses		**(15)**		(17)
NMGC gas hedge settlement receivable (2)		**-**		162
Other		**191**		360
Total receivables and other current assets	**$**	**1,817**	$	2,897

(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.
(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. For more information, refer to note 6.

19. 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 62 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 2023**		December 31 2022
Right-of-use asset	Other long-term assets	**$**	**54**	**$**	58
Lease liabilities					
Current	Other current liabilities		**3**		3
Long-term	Other long-term liabilities		**55**		59
Total lease liabilities		**$**	**58**	**$**	62

The Company recorded lease expense of $127 million for the year ended December 31, 2023 (2022 – $138 million), of which $119 million (2022 – $131 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	2024	2025	2026	2027	2028	Thereafter	Total
Minimum lease payments	$ 6	$ 5	$ 3	$ 3	$ 3	$ 111	$ 131
Less imputed interest							(73)
Total							$ 58

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

	Year ended December 31	
For the	**2023**	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of dollars)	**$ 8**	$ 8
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of dollars)	**$ 1**	$ 1
Weighted average remaining lease term (years)	**44**	44
Weighted average discount rate- operating leases	**3.93%**	3.98%

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.

Commencing in January 2022, the Company leased Seacoast pipeline, a 21-mile, 30-inch lateral that is classified as a sales-type lease. The term of the pipeline lateral lease is 34 years with a net investment of $100 million USD. The lessee of the pipeline lateral has renewal options for an additional 16 years. These renewal options have not been included as part of the pipeline lateral lease term as it is not reasonably certain that they will be exercised.

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 2023**		December 31 2022
Total minimum lease payment to be received	**$**	**1,360**	$	1,393
Less: amounts representing estimated executory costs		**(190)**		(205)
Minimum lease payments receivable	**$**	**1,170**	$	1,188
Estimated residual value of leased property (unguaranteed)		**183**		183
Less: Credit loss reserve		**(2)**		-
Less: unearned finance lease income		**(693)**		(733)
Net investment in direct finance and sales-type leases	**$**	**658**	$	638
Principal due within one year (included in "Receivables and other current assets")		**37**		34
Net Investment in direct finance and sales type leases - long-term	**$**	**621**	$	604

As at December 31, 2023, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars		2024		2025		2026		2027		2028		Thereafter		Total
Minimum lease payments to be received	$	97	$	99	$	98	$	97	$	96	$	873	$	1,360
Less: executory costs														(190)
Total													$	1,170

20. 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 2023**		December 31 2022
Generation	3 to 131	**$**	**13,500**	$	13,083
Transmission	10 to 80		**2,835**		2,731
Distribution	4 to 80		**7,417**		6,978
Gas transmission and distribution	6 to 92		**5,536**		5,061
General plant and other (1)	2 to 71		**2,985**		2,723
Total cost			**32,273**		30,576
Less: Accumulated depreciation (1)			**(9,994)**		(9,574)
			22,279		21,002
Construction work in progress (1)			**2,097**		1,994
Net book value		**$**	**24,376**	$	22,996

(1) 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, 2023, SeaCoast's share of plant in service was $27 million USD (2022 – $27 million USD), and accumulated depreciation of $2 million USD (2022 – $1 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.

21. 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. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, New Mexico, Barbados, and Grand Bahama Island.

Emera's net periodic benefit cost included the following:

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

For the millions of dollars				Year ended December 31
		2023		2022
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 2,158**	**$ 243**	$ 2,624	$ 318
Service cost	**30**	**3**	41	4
Plan participant contributions	**6**	**6**	6	6
Interest cost	**111**	**13**	80	9
Plan amendments	**-**	**(14)**	-	-
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actuarial losses (gains)	**146**	**10**	(480)	(79)
Settlements and curtailments	**(8)**	**-**	(6)	-
FX translation adjustment	**(23)**	**(5)**	67	16
Balance, December 31	**$ 2,273**	**$ 227**	$ 2,158	$ 243
Change in plan assets				
Balance, January 1	**$ 2,163**	**$ 46**	$ 2,702	$ 51
Employer contributions	**42**	**23**	45	24
Plan participant contributions	**6**	**6**	6	6
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actual return on assets, net of expenses	**262**	**3**	(489)	(7)
Settlements and curtailments	**(8)**	**-**	(6)	**-**
FX translation adjustment	**(20)**	**(1)**	79	3
Balance, December 31	**$ 2,298**	**$ 48**	$ 2,163	$ 46
Funded status, end of year	**$ 25**	**$ (179)**	$ 5	$ (197)

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 all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeded the plan assets for the years ended December 31 was as follows:

millions of dollars		**2023**		2022
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 120**	**$ 205**	$ 1,006	$ 221
FV of plan assets	**37**	**-**	914	-
Funded status	**$ (83)**	**$ (205)**	$ (92)	$ (221)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets:
The ABO for the DB pension plans was $2,172 million as at December 31, 2023 (2022 – $2,080 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 was as follows:

millions of dollars	**2023**	2022
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 114**	$ 111
FV of plan assets	**37**	33
Funded status	**$ (77)**	$ (78)

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

As at millions of dollars	**December 31 2023**		December 31 2022	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (5)**	**$ (18)**	$ (13)	$ (20)
Long-term liabilities	**(78)**	**(187)**	(80)	(201)
Other long-term assets	**108**	**26**	98	24
AOCI, net of tax and regulatory assets	**385**	**20**	358	22
Less: Deferred income tax (expense) recovery in AOCI	**(8)**	**(1)**	(7)	(1)
Net amount recognized	**$ 402**	**$ (160)**	$ 356	$ (176)

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) costs
Defined Benefit Pension Plans			
Balance, January 1, 2023	$ 336	$ 15	$ -
Amortized in current period	(6)	(3)	-
Current year additions	1	41	-
Change in FX rate	(7)	-	-
Balance, December 31, 2023	$ 324	$ 53	$ -
Non-pension benefits plans			
Balance, January 1, 2023	$ 31	$ (10)	$ -
Amortized in current period	2	3	-
Current year reductions	(3)	(1)	(3)
Change in FX rate	(1)	-	1
Balance, December 31, 2023	$ 29	$ (8)	$ (2)

As at millions of dollars	**December 2023**		December 2022	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 53**	**(8)**	$ 15	$ (10)
Past service gains	**-**	**(2)**	-	-
Deferred income tax expense	**8**	**1**	7	1
AOCI, net of tax	**61**	**(9)**	22	(9)
Regulatory assets	**324**	**29**	336	31
AOCI, net of tax and regulatory assets	**$ 385**	**$ 20**	$ 358	$ 22

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

As at millions of dollars			Year ended December 31 2023	
				2022
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 30**	**$ 3**	$ 41	$ 4
Interest cost	**111**	**13**	80	9
Expected return on plan assets	**(161)**	**(2)**	(144)	-
Current year amortization of:				
Actuarial losses (gains)	**1**	**(3)**	8	-
Regulatory assets (liability)	**6**	**(2)**	21	2
Settlement, curtailments	**2**	**-**	2	-
Total	**$ (11)**	**$ 9**	$ 8	$ 15

The expected return on plan assets is determined based on the market-related value of plan assets of $2,577 million as at January 1, 2023 (2022 – $2,482 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year 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 five-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. Within each asset class, a further 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:

Canadian Pension Plans

Asset Class	Target Range at Market		
Short-term securities	0%	to	10%
Fixed income	34%	to	49%
Equities:			
Canadian	7%	to	17%
Non-Canadian	35%	to	59%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
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:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
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 %**

As at					December 31, 2022
Cash and cash equivalents	$ -	$ 70	$ -	$ 70	3 %
Net in-transits	-	(70)	-	(70)	(3)%
Equity securities:					
Canadian equity	-	87	-	87	4 %
United States equity	-	233	-	233	11 %
Other equity	-	186	-	186	8 %
Fixed income securities:					
Government	-	-	104	104	5 %
Corporate	-	-	83	83	4 %
Other	-	3	11	14	1 %
Mutual funds	-	68	-	68	3 %
Other	-	-	(3)	(3)	- %
Open-ended investments measured at NAV (1)	790	-	-	790	36 %
Common collective trusts measured at NAV (2)	601	-	-	601	28 %
Total	$ 1,391	$ 577	$ 195	$ 2,163	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.

Refer to note 16 for more information on the FV hierarchy and inputs used to measure FV.

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

Investments in Emera:
As at December 31, 2023 and 2022, 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	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2024	$ 34	$ 19
Expected benefit payments		
2024	172	21
2025	163	21
2026	166	21
2027	171	21
2028	173	20
2029 – 2033	890	95

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

		2023		2022
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – 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 %
Rate of compensation increase	**3.87 %**	**3.85 %**	3.62 %	3.61 %
Health care trend - initial (next year)	**-**	**6.04 %**	-	5.40 %
- ultimate	**-**	**3.76 %**	-	3.77 %
- year ultimate reached		**2043**		2043
Benefit cost for year ended December 31:				
Discount rate - past service	**5.33 %**	**5.31 %**	3.05 %	2.81 %
Discount rate - future service	**5.34 %**	**5.32 %**	3.18 %	2.92 %
Expected long-term return on plan assets	**6.56 %**	**2.16 %**	6.07 %	1.32 %
Rate of compensation increase	**3.62 %**	**3.61 %**	3.31 %	3.29 %
Health care trend - initial (current year)	**-**	**5.40 %**	-	5.09 %
- ultimate	**-**	**3.77 %**	-	3.77 %
- year ultimate reached		**2043**		2042

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.

Defined Contribution Plan:
Emera also provides a DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2023 was $45 million (2022 – $41 million).

22. GOODWILL

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

millions of dollars		**2023**		2022
Balance, January 1	**$**	**6,012**	$	5,696
Change in FX rate		**(141)**		389
GBPC impairment charge		**-**		(73)
Balance, December 31	**$**	**5,871**	$	6,012

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, 2023, primarily related to TECO Energy (reporting units with goodwill are TEC, PGS, and NMGC).

In 2023, Emera performed qualitative impairment assessments for NMGC and PGS, concluding that the FV of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income approach and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

In 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach. It was determined that the FV did not exceed its carrying amount, including goodwill. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. This non-cash charge is included in "GBPC impairment charge" on the Consolidated Statements of Income.

23. 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		**2023**	**Weighted average interest rate**		2022	Weighted average interest rate
TEC						
Advances on revolving credit facilities	**$**	**277**	**5.68 %**	$	1,380	5.00 %
Emera						
Non-revolving term facilities		**796**	**6.07 %**		796	5.19 %
Bank indebtedness		**9**	**- %**		-	- %
TECO Finance						
Advances on revolving credit and term facilities		**245**	**6.54 %**		481	5.47 %
PGS						
Advances on revolving credit facilities		**73**	**6.36 %**		-	- %
NMGC						
Advances on revolving credit facilities		**25**	**6.46 %**		59	5.15 %
GBPC						
Advances on revolving credit facilities		**8**	**5.54 %**		10	5.25 %
Short-term debt	**$**	**1,433**		$	2,726	

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

millions of dollars	Maturity		**2023**	2022
TEC - Unsecured committed revolving credit facility	2026	**$**	**401** $	1,084
TECO Energy/TECO Finance - revolving credit facility	2026		**-**	542
TECO Finance - Unsecured committed revolving credit facility	2026		**529**	-
Emera - Unsecured non-revolving term facility	2024		**400**	400
Emera - Unsecured non-revolving term facility	2024		**400**	400
PGS - Unsecured revolving credit facility	2028		**331**	-
TEC - Unsecured revolving facility	2024		**265**	542
TEC - Unsecured revolving facility	2024		**265**	-
NMGC - Unsecured revolving credit facility	2026		**165**	169
Other - Unsecured committed revolving credit facilities	Various		**17**	18
Total		**$**	**2,773** $	3,155
Less:				
Advances under revolving credit and term facilities			**1,433**	2,731
Letters of credit issued within the credit facilities			**3**	4
Total advances under available facilities			**1,436**	2,735
Available capacity under existing agreements		**$**	**1,337** $	420

The weighted average interest rate on outstanding short-term debt at December 31, 2023 was 5.95 per cent (2022 – 5.01 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

Gas Utilities and Infrastructure

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin.

Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

24. OTHER CURRENT LIABILITIES

As at millions of dollars	**December 31 2023**	December 31 2022
Accrued charges	**$ 172**	$ 174
Nova Scotia Cap-and-Trade Program provision (note 6)	**-**	172
Accrued interest on long-term debt	**107**	97
Pension and post-retirement liabilities (note 21)	**23**	33
Sales and other taxes payable	**11**	14
Income tax payable	**2**	9
Other	**112**	80
	$ 427	$ 579

25. 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) 2023	2022	Maturity	2023	2022
Emera					
Bankers acceptances, SOFR loans	Variable	Variable	2027	**$ 465**	$ 403
Unsecured fixed rate notes	4.84%	2.90%	2030	**500**	500
Fixed to floating subordinated notes (2)	6.75%	6.75%	2076	**1,587**	1,625
				$ 2,552	$ 2,528
Emera Finance					
Unsecured senior notes	3.65%	3.65%	2024 - 2046	**$ 3,637**	$ 3,725
TEC (3)					
Fixed rate notes and bonds	4.61%	4.15%	2024 - 2051	**$ 5,654**	$ 4,341
PGS					
Fixed rate notes and bonds	5.63%	3.78%	2028 - 2053	**$ 1,223**	$ 772
NMGC					
Fixed rate notes and bonds	3.78%	3.11%	2026 - 2051	**$ 642**	$ 521
Non-revolving term facility, floating rate	Variable	Variable	2024	**30**	108
				$ 672	$ 629
NMGI					
Fixed rate notes and bonds	3.64%	3.64%	2024	**$ 198**	$ 203
NSPI					
Discount Notes (4)	Variable	Variable	2024 - 2027	**$ 721**	$ 881
Medium term fixed rate notes	5.13%	5.14%	2025 - 2097	**3,165**	2,665
				$ 3,886	$ 3,546
EBP					
Senior secured credit facility	Variable	Variable	2026	**$ 246**	$ 249
ECI					
Secured senior notes	Variable	Variable	2027	**$ 75**	$ 86
Amortizing fixed rate notes	4.00%	3.97%	2026	**79**	100
Non-revolving term facility, floating rate	Variable	Variable	2025	**29**	30
Non-revolving term facility, fixed rate	2.15%	2.05%	2025 - 2027	**155**	91
Secured fixed rate senior notes (5)	3.09%	3.06%	2024 - 2029	**84**	142
				$ 422	$ 449
Adjustments					
Fair market value adjustment - TECO Energy acquisition				**$ -**	$ 2
Debt issuance costs				**(125)**	(126)
Amount due within one year				**(676)**	(574)
				$ (801)	$ (698)
Long-Term Debt				**$ 17,689**	$ 15,744

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2023, the Company recognized $109 million in interest expense (2022 – $110 million) related to its fixed to floating subordinated notes.
(3) A substantial part of TEC's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under TEC's first mortgage bond indenture.
(4) Discount notes are backed by a revolving credit facility which matures in 2027. Banker's acceptances are issued under NSPI's non-revolving term facility which matures in 2024. NSPI has the intention and unencumbered ability to refinance bankers' acceptances for a period of greater than one year.
(5) Notes are issued and payable in either USD or BBD.

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	2023	2022
Emera – revolving credit facility (1)	June 2027	**$ 900**	$ 900
TEC - Unsecured committed revolving credit facility	December 2026	**657**	-
NSPI - revolving credit facility (1)	December 2027	**800**	800
NSPI - non-revolving credit facility	July 2024	**400**	400
Emera - Unsecured non-revolving credit facility	February 2024	**400**	-
NMGC - Unsecured non-revolving credit facility	March 2024	**30**	108
ECI – revolving credit facilities	October 2024	**10**	11
Total		**$ 3,197**	$ 2,219
Less:			
Borrowings under credit facilities		**1,884**	1,396
Letters of credit issued inside credit facilities		**6**	12
Use of available facilities		**$ 1,890**	$ 1,408
Available capacity under existing agreements		**$ 1,307**	$ 811

(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, 2023
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

Recent Significant Financing Activity by Segment

Florida Electric Utility

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 repayment of short-term borrowings outstanding under the 5-year credit facility. Therefore, $497 million USD of short-term borrowings that were repaid was classified as long-term debt at December 31, 2023.

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053.

Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033.

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028.

Other

On August 18, 2023, Emera entered into a $400 million non-revolving term facility with a maturity date of February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030.

Long-Term Debt Maturities

As at December 31, 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	2024	2025	2026	2027	2028	Thereafter	Total
Emera	$ 199	$ -	$ 1,587	$ 266	$ -	$ 500	$ 2,552
Emera US Finance LP	397	-	992	-	-	2,248	3,637
TEC	397	-	-	-	-	5,257	5,654
PGS	-	-	-	-	463	760	1,223
NMGC	30	-	93	-	-	549	672
NMGI	198	-	-	-	-	-	198
NSPI	398	125	40	323	-	3,000	3,886
EBP	-	-	246	-	-	-	246
ECI	51	139	89	77	62	4	422
Total	$ 1,670	$ 264	$ 3,047	$ 666	$ 525	$ 12,318	$ 18,490

26. 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	**2023**	2022
Balance, January 1	**$ 174**	$ 174
Accretion included in depreciation expense	**9**	9
Change in FX rate	**(1)**	3
Additions	**-**	1
Accretion deferred to regulatory asset (included in PP&E)	**18**	1
Liabilities settled	**(8)**	(1)
Revisions in estimated cash flows	**-**	(13)
Balance, December 31	**$ 192**	$ 174

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2023, 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	2024	2025	2026	2027	2028	Thereafter	Total
Transportation (1)	$ 696	$ 495	$ 405	$ 388	$ 338	$ 2,597	$ 4,919
Purchased power (2)	274	249	263	312	312	3,435	4,845
Fuel, gas supply and storage	556	215	62	-	5	-	838
Capital projects	778	111	70	1	-	-	960
Equity investment commitments (3)	240	-	-	-	-	-	240
Other	154	147	56	46	35	221	659
	$ 2,698	$ 1,217	$ 856	$ 747	$ 690	$ 6,253	$ 12,461

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 million related to a gas transportation contract between PGS and SeaCoast through 2040.

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

(3) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

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 February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. In December 2023, the UARB approved the collection of up to $164 million from NSPI for the recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Construction of the LIL is complete, and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Emera has committed to obtain certain transmission rights for Nalcor, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets 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, 2023, the aggregate financial liability of the Florida utilities is estimated to be $15 million ($11 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 materially affect the Company in the normal course of business. Risks associated with derivative instruments and FV measurements are discussed in note 15 and note 16.

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 an effective, consistent and coherent approach to risk management. The Board of Directors has a Risk and Sustainability Committee ('RSC") with a mandate that includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks. It also includes oversight of the Company's approach to sustainability and its performance relative to its sustainability objectives.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. Regulatory and political risk can include changes in regulatory frameworks, shifts in government policy, legislative changes, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, and M&NP. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement, expiring in 2034, with Repsol Energy North America Canada Partnership.

Regulators administer the regulatory frameworks covering material aspects of the utilities' businesses, including applying market-based tests to determine the appropriate customer rates and/or riders, the underlying allowed ROEs, deemed capital structures, capital investment, the terms and conditions for the provision of service, performance standards, and affiliate transactions. Regulators also review the prudency of costs and other decisions that impact customer rates and reliability of service and work to ensure the financial health of the utility for the benefit of customers. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally require a public hearing process or may be mandated by other governmental bodies. During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. Regulatory decisions, legislative changes, and prolonged delays in the recovery of costs or regulatory assets could result in decreased rate affordability for customers and could materially affect Emera and its utilities.

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

Changes in government and shifts in government policy and legislation can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect the Company's operations, net income and cash flows. State and local policies in some United States jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas while in other jurisdictions policies have been adopted to prevent limitations on the use of natural gas. Changes in applicable state or local laws and regulations, including electrification legislation, could adversely impact PGS and NMGC.

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or its ability to respond in an effective and timely manner or the resulting compliance costs. Government interference in the regulatory process can undermine regulatory stability, predictability, and independence, and could have a material adverse effect on the Company.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, with an increasing 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.

Consistent with the Company's risk management policies, Emera manages currency risks through matching United States denominated debt to finance its United States 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 Market Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets.

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 more information on interest rate risk, refer to "General Economic Risk – Interest Rate Risk". 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. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

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 materially affect Emera and its utilities. 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. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

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 Market 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. Emera's utilities have budgeting and forecasting processes to identify inflationary risk factors and measure operating performance, as well as collective bargaining agreements that mitigate the short-term impact of inflation on labour costs of unionized employees.

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.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. These include the Company's commercial arrangements, such as the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

Regulated Utilities:
The Company's utility fuel supply is exposed to broader global 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, trade sanctions or embargos. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated electric and gas utilities have adopted and implemented fuel adjustment mechanisms and purchased gas adjustment mechanisms respectively, which further helps manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel and gas costs. There is no assurance that such mechanisms and regulatory frameworks will continue to exist in the future. 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.

Emera Energy Marketing and Trading:
Emera Energy has employed further measures to manage commodity risk. 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 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.

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV that could occur from changes in Emera Energy's portfolio or changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. 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. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

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 are not included within the Consolidated Balance Sheets as at December 31, 2023:

TECO Energy has issued 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. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's Investor Services ("Moody's") or S&P Global Ratings ("S&P"). TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

TECO Energy issued a guarantee in connection with SeaCoast's performance obligations under a firm service agreement, which expires on 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. In the event that TECO Energy's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would need to provide 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 Inc. has issued 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 issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 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 Inc., 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

Collaborative Arrangements

For the years ended December 31, 2023 and 2022, 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 2023, NSPI recognized $8 million net expense (2022 – $12 million) in "Regulated fuel for generation and purchased power" and $3 million (2022 – $3 million) in "OM&G" on the Consolidated Statements of Income.

28. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

			December 31, 2023		December 31, 2022	
	Annual Dividend Per Share	Redemption Price per share	**Issued and Outstanding**	**Net Proceeds**	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)	Initial Yield (%)	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	4.400	0.5456	1.84	August 15, 2025	25.00	Series B
Series C (5)(6)	4.100	1.6085	2.65	August 15, 2028	25.00	Series D
Series F	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 (5)(7)	4.900	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 (8)	4.500	1.1250			25.00	
Series L (9)	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 July 6, 2023, Emera announced it would not redeem the outstanding Preferred Shares, Series C and Series H on August 15, 2023. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Series D Shares and no Series H Shares were converted into Series I shares.
(6) The annual fixed dividend per share for Series C Shares was reset from $1.1802 to $1.6085 for the five-year period from and including August 15, 2028.
(7) The annual fixed dividend per share for Series H Shares was reset from $1.2250 to $1.5810 for the five-year period from and including August 15, 2028.
(8) First Preferred Shares, Series E are redeemable at $25.00 per share.
(9) 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.

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of dollars		December 31 **2023**		December 31 2022
Preferred shares of GBPC	**$**	**14**	$	14
	$	**14**	$	14

Preferred shares of GBPC:

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

			2023			2022
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.

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of dollars		Year ended December 31 **2023**		2022
Changes in non-cash working capital:				
Inventory	**$**	**(31)**	$	(214)
Receivables and other current assets (1)		**653**		(636)
Accounts payable		**(538)**		423
Other current liabilities (2)		**(179)**		193
Total non-cash working capital	**$**	**(95)**	$	(234)

(1) Includes $162 million related to the January 2023 settlement of NMGC gas hedges (2022 – ($162) million). Offsetting regulatory liability is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) Includes ($166) million related to the Nova Scotia Cap-and-Trade program (2022 – $172 million). For further detail, refer to note 6. 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 **2023**		2022
Supplemental disclosure of cash paid:				
Interest	**$**	**930**	$	699
Income taxes	**$**	**43**	$	67
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**271**	$	237
Decrease in accrued capital expenditures	**$**	**(19)**	$	(13)
Reclassification of short-term debt to long-term debt	**$**	**657**	$	-
Reclassification of long-term debt to short-term debt	**$**	**-**	$	500
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**123**	$	(157)

31. STOCK-BASED COMPENSATION

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in the ECSPP. As of December 31, 2023, the plan allows employees to make cash contributions of a minimum of $25 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 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, 2023, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSPP for the year ended December 31, 2023 was $3 million (2022 – $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 in connection with the reinvestment of cash dividends. The discount was 2 per cent in 2023.

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, 2023, 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:

	2023	2022
Weighted average FV per option	**$ 6.32**	$ 5.35
Expected term (1)	**5 years**	5 years
Risk-free interest rate (2)	**3.53 %**	1.79 %
Expected dividend yield (3)	**5.05 %**	4.55 %
Expected volatility (4)	**20.07 %**	18.87 %

(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 2023:

	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, 2022	2,853,879	$ 50.41	1,348,400	$ 4.08
Granted	483,100	54.64	483,100	6.32
Exercised	(146,475)	43.94	N/A	N/A
Forfeited	(94,900)	56.32	(51,625)	3.61
Vested	N/A	N/A	(526,620)	3.58
Options outstanding December 31, 2023	**3,095,604**	**$ 51.20**	**1,253,255**	**$ 5.17**
Options exercisable December 31, 2023 (2)(3)	**1,842,349**	**$ 48.39**		

(1) As at December 31, 2023, there was $5 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 (2022 – $4 million, 3 years).
(2) As at December 31, 2023, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $8 million (2022 – 5 years, $10 million).
(3) As at December 31, 2023, the FV of options that vested in the year was $2 million (2022 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2023 was $2 million (2022 – $2 million), which was included in “OM&G” on the Consolidated Statements of Income.

As at December 31, 2023, cash received from option exercises was $6 million (2022 – $9 million). The total intrinsic value of options exercised for the year ended December 31, 2023 was $2 million (2022 – $4 million). The range of exercise prices for the options outstanding as at December 31, 2023 was $32.35 to $60.03 (2022 – $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. 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 Management Resources and Compensation Committee ("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, 2023 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, 2022	627,223	$ 41.55	664,258	$ 45.83
Granted including DRIP	85,740	47.66	117,893	49.99
Exercised	N/A	N/A	(53,093)	49.39
Outstanding and exercisable as at December 31, 2023	**712,963**	**$ 42.29**	**729,058**	**$ 46.24**

Compensation cost recovery recognized for employee and director DSU's for the year ended December 31, 2023 was $2 million (2022 – $6 million). Tax expense related to this compensation cost recovery for share units realized for the year ended December 31, 2023 was $1 million (2022 – $2 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for employees was $36 million (2022 – $33 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for directors was $37 million (2022 – $34 million). Cash payments made during the year ended December 31, 2023 associated with the DSU plan were $3 million (2022 – $8 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. 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, 2023 is presented in the following table:

	Employee PSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	690,446	$	56.24	$	40
Granted including DRIP	386,261		52.71		
Exercised	(323,155)		54.62		
Forfeited	(10,187)		55.15		
Outstanding as at December 31, 2023	**743,365**	**$**	**55.13**	**$**	**41**

Compensation cost recognized for the PSU plan for the year ended December 31, 2023 was $11 million (2022 – $18 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $5 million). Cash payments made during the year ended December 31, 2023 associated with the PSU plan were $19 million (2022 – $24 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. 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, 2023 is presented in the following table:

	Employee RSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	508,468	$	56.25	$	30
Granted including DRIP	236,537		52.07		
Exercised	(171,537)		54.62		
Forfeited	(10,827)		54.76		
Outstanding as at December 31, 2023	**562,641**	**$**	**55.01**	**$**	**32**

Compensation cost recognized for the RSU plan for the year ended December 31, 2023 was $10 million (2022 – $9 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $2 million). Cash payments made during the year ended December 31, 2023 associated with the RSU plan were $10 million (2022– nil).

32. 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, Nalcor Energy 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, 2023**		December 31, 2022	
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)	**$ 489**	**$ 6**	$ 501	$ 6

33. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 26, 2024, the date the financial statements were issued.