Management's Discussion & Analysis

As at February 21, 2025

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as "Emera" or the "Company") during the fourth quarter of, and for the full year of, 2024 relative to the same periods in 2023 and selected financial information for 2022; and its financial position as at December 31, 2024 relative to December 31, 2023. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2024. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to Emera, including the Company's Annual Information Form, can be found on Sedar+ at www.sedarplus.ca.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2024, Emera's rate-regulated subsidiaries and investments include:

Rate-Regulated Subsidiary or Equity Investment	Accounting Policies Approved/Examined By
Subsidiary	
Tampa Electric Company ("TEC")	Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC")
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Peoples Gas System, Inc. ("PGS")	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	Canadian Energy Regulator ("CER")
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP")	CER and FERC
St. Lucia Electricity Services Limited ("Lucelec")	National Utility Regulatory Commission

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Gas Utilities and Infrastructure, and Other Electric Utilities sections of the MD&A, which are reported in United States dollars ("USD") unless otherwise stated.

TABLE OF CONTENTS

FORWARD-LOOKING INFORMATION

This MD&A contains “forward-looking information” (“FLI”) and statements which reflect the current view with respect to the Company’s expectations regarding future growth, results of operations, performance, the expected timing and outcome of the pending sale of NMGC, business prospects and opportunities, and may not be appropriate for other purposes within the meaning of applicable Canadian securities laws. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecast”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “targets”, “will”, “would” and similar expressions are often intended to identify FLI, although not all FLI contains these identifying words. The FLI reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

FLI is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the FLI. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; change in law risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital markets risk; changes in credit ratings; future dividend growth, rate base growth, and adjusted earnings per common share (“EPS”) growth; timing and costs associated with certain capital investments; expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; climate change risk; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange (“FX”); regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology (“IT”) infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on FLI, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the FLI. All FLI in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any FLI as a result of new information, future events or otherwise.

INTRODUCTION AND STRATEGIC OVERVIEW

Emera (TSX: EMA) is a North American provider of energy services, owning and operating a portfolio of cost-of-service, rate-regulated electric and gas utilities. Its largest operations are in Florida, with additional operations in Atlantic Canada, New Mexico, and the Caribbean. Emera is headquartered in Halifax, Nova Scotia.

Emera's business strategy is centered on continued investment in its regulated utilities, combined with a focus on operational excellence and efficiency, to safely and reliably deliver energy to its 2.6 million customers. Effective execution of these priorities supports predictable and growing earnings, cash flow and dividends for shareholders.

Earnings opportunities in regulated utilities are a function of the magnitude of net investment in the utility (known as "rate base"), the amount of equity in the capital structure, and the targeted return on that equity ("ROE"), all as established and approved through regulation. Earnings are also affected by sales volumes and operating expenses. In 2024, Emera's regulated cost-of-service utilities in Florida accounted for 65 per cent of average consolidated rate base, with Atlantic Canada comprising 27 per cent, and the Caribbean and New Mexico at 4 per cent each.

Emera's capital investment plan is forecasted to be approximately $20 billion from 2025 through 2029 and is focused on delivering value for customers through prudent investments in reliability and system resiliency, infrastructure modernization, expansion to address customer growth, integration of renewables, and technological innovations to deliver better customer experiences. It is anticipated that approximately 80 per cent of this capital investment will be made in Emera's Florida utilities, necessitated by customer growth and system requirements at both TEC and PGS.

As at millions of dollars	2025	2026	2027	2028	2029	Total
Capital investment plan	$ 3,420	$ 3,990	$ 4,050	$ 4,380	$ 4,590	$ 20,430
Average consolidated rate base						
US operations	$ 21,520	$ 23,340	$ 25,140	$ 27,050	$ 29,400	
Canadian operations	7,630	8,000	8,370	8,590	8,870	
Total	$ 29,150	$ 31,340	$ 33,510	$ 35,640	$ 38,270	

*Capital investment plan and average consolidated rate base exclude NMGC. Refer to "Other Developments" for more information on the pending sale of NMGC

Emera's capital investment plan will be funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity issuances, and the anticipated sale of NMGC. Generally, Emera's equity requirements are expected to be funded through the issuance of preferred equity, and the issuance of common equity through Emera's dividend reinvestment plan ("DRIP") and its at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a core strategic priority of the Company.

Emera has increased dividends per common share paid for 18 consecutive years and has provided forward annual dividend growth guidance of one to two per cent. Emera's anticipates adjusted EPS average growth of five to seven per cent through 2027 which will support reduction in the ratio of dividend payout to adjusted net income. For further information on the non-GAAP ratios "Adjusted EPS" and "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section.

NON-GAAP FINANCIAL MEASURES AND RATIOS

Emera uses financial measures and ratios that do not have standardized meaning under USGAAP and are calculated by adjusting certain GAAP measures for specific items. They may not be comparable to similar measures presented by other entities. These measures and ratios are discussed and reconciled below.

Adjusted Net Income, Adjusted EPS – Basic, and Dividend Payout Ratio of Adjusted Net Income

Emera calculates an adjusted net income attributable to common shareholders (“adjusted net income”) measure by excluding items below from net income attributable to common shareholders. Management believes excluding these items better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business.

Emera calculates adjusted net income for the Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. For more information refer to the Financial Highlights section for each of Florida Electric Utility, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

Adjusted EPS – basic and dividend payout ratio of adjusted net income are non-GAAP ratios which are calculated using adjusted net income, as described above. For further details on dividend payout ratio of adjusted net income, refer to the “Dividend Payout Ratio” section.

Adjusting item impacting all periods:

Mark-to-market (“MTM”) Adjustments:
Management believes excluding from net income the effect of MTM valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows, and therefore excludes MTM adjustments for evaluation of performance and incentive compensation. The MTM adjustments are related to the following:

- held-for-trading (“HFT”) commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered, and the related amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the business activities of Bear Swamp Power Company LLC (“Bear Swamp”) included in Emera’s equity income;
- equity securities held in BLPC and Emera Energy; and
  FX hedges entered into to hedge USD denominated operating unit earnings exposure.

Adjusting items impacting 2024:

Gain on Sale of Emera’s Indirect Minority Interest in the LIL (“Gain on sale of LIL”):
In Q2 2024, Emera recognized a $107 million gain, after tax and transaction costs, on the sale of LIL. In Q4 2024, Emera recognized a $22 million tax benefit related to the reversal of a prior year valuation allowance. A portion of the taxable capital gain on sale of LIL was offset by prior year loss carryforwards, of which the tax benefit was subject to a valuation allowance as at December 31, 2023. For further details refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

Financing Structure Wind-Up:
In Q4 2024, Emera recognized a $58 million tax benefit related to denied interest and financing expenses and the wind-up of a specific financing structure. For further details refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

Charges Related to Wind-Down Costs and Certain Asset Impairments:
In Q4 2024, the Company recognized $26 million, after-tax, in wind-down costs and certain asset impairments, primarily at Block Energy LLC ("Block Energy"). For further details, refer to the "Significant Items Affecting Earnings" section.

Charges Related to the Pending Sale of NMGC:
On August 5, 2024, Emera entered into an agreement to sell NMGC. In Q3 2024, the Company recognized $206 million in non-cash goodwill and other impairment charges, after-tax, and an additional loss of $19 million in estimated transaction costs, after-tax, related to the pending sale. For further details, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

Adjusting items impacting 2022:

GBPC Impairment Charge:
In Q4 2022, the Company recognized a $73 million non-cash goodwill impairment charge related to GBPC due to a decline in the fair value ("FV") of the reporting unit.

NSPML Unrecoverable Costs:
In Q1 2022, the UARB issued a decision to disallow recovery of $9 million in costs ($7 million after-tax) included in NSPML's final capital cost application.

Reconciliation of Net Income Attributable to Common Shareholders to Adjusted Net Income:

For the	Three months ended December 31		Year ended December 31		
millions of dollars (except per share amounts)	**2024**	2023	**2024**	2023	2022
Net income attributable to common shareholders	**$ 154**	$ 289	**$ 494**	$ 978	$ 945
Gain on sale of LIL, after-tax (1)	**22**	-	**129**	-	-
Financing structure wind-up	**58**	-	**58**	-	-
Charges related to wind-down costs and certain asset impairments, after-tax (2)	**(26)**	-	**(26)**	-	-
Charges related to the pending sale of NMGC, after-tax (3)(4)	**-**	-	**(225)**	-	-
MTM (loss) gain, after-tax (5)	**(146)**	114	**(291)**	169	175
GBPC impairment charge	**-**	-	**-**	-	(73)
NSPML unrecoverable costs	**-**	-	**-**	-	(7)
Adjusted net income	**$ 246**	$ 175	**$ 849**	$ 809	$ 850
EPS – basic	**$ 0.52**	$ 1.04	**$ 1.71**	$ 3.57	$ 3.56
Adjusted EPS – basic	**$ 0.84**	$ 0.63	**$ 2.94**	$ 2.96	$ 3.20

(1) Includes an income tax recovery of $22 million for the three months ended December 31, 2024 and net of income tax expense of $53 million for the year ended December 31, 2024 (2023 – nil).
(2) Net of income tax recovery of $6 million for the three months and year ended December 31, 2024 (2023 – nil).
(3) Represents (i) $206 million in non-cash goodwill and other impairment charges, after-tax and (ii) $19 million in transaction costs, after-tax for the year ended December 31, 2024 (2023 – nil).
(4) Net of income tax recovery of $21 million for the year ended December 31, 2024 (2023 – nil).
(5) Net of income tax recovery of $57 million for the three months ended December 31, 2024 (2023 – $44 million expense) and $117 million recovery for the year ended December 31, 2024 (2023 – $68 million expense) (2022 – $73 million expense).

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital, and finance working capital requirements.

Adjusted EBITDA represents EBITDA excluding the income effect of the gain on sale of LIL, charges related to wind-down costs and certain asset impairments, charges related to the pending sale of NMGC, MTM adjustments, the 2022 GBPC impairment charge, and the 2022 NSPML unrecoverable costs.

Reconciliation of Net Income to EBITDA and Adjusted EBITDA:

For the millions of dollars	Three months ended December 31 **2024**	 2023	Year ended December 31 **2024**	 2023	 2022
Net income (1)	**$ 173**	$ 307	**$ 568**	$ 1,045	$ 1,009
Interest expense, net	**248**	241	**973**	925	709
Income tax (recovery) expense	**(199)**	51	**(159)**	128	185
Depreciation and amortization	**296**	264	**1,162**	1,049	952
EBITDA	**$ 518**	$ 863	**$ 2,544**	$ 3,147	$ 2,855
Gain on sale of LIL, excluding income tax	**-**	-	**182**	-	-
Charges related to wind-down costs and certain asset impairments, excluding income tax	**(32)**	-	**(32)**	-	-
Charges related to the pending sale of NMGC, excluding income tax	**-**	-	**(246)**	-	-
MTM (loss) gain, excluding income tax	**(203)**	158	**(408)**	237	248
GBPC impairment charge	**-**	-	**-**	-	(73)
NSPML unrecoverable costs	**-**	-	**-**	-	(7)
Adjusted EBITDA	**$ 753**	$ 705	**$ 3,048**	$ 2,910	$ 2,687

(1) Net income is before Non-controlling interest in subsidiaries and Preferred stock dividends.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

The items detailed below have had a significant impact on Net Income Attributable to Common Shareholders but have been excluded from Adjusted Net Income as described in the section entitled "Non-GAAP Financial Measures and Ratios".

Financing Structure Wind-Up

During 2024, the Company incurred $185 million of interest and financing expenses in connection with a specific financing structure. The current and future interest and financing expenses are expected to be denied under the recently enacted Excessive Interest and Financing Expenses Limitation ("EIFEL") legislation and, as a result, the financing structure has been wound up. It was determined that Emera is more likely than not to realize the benefit of the current denied interest and financing expenses in future periods and therefore a $54 million deferred income tax asset and related income tax benefit ($0.19 per common share) was recorded during Q4 2024. In addition, Emera recognized a $4 million income tax benefit ($0.01 per common share) related to the reversal of a deferred income tax liability on the wind-up of the financing structure. The total tax benefit of $58 million was recorded in "Income Tax (Recovery) Expense" on the Consolidated Statements of Income and included in the Other segment. For further details on the EIFEL legislation, refer to the "Other Developments" section.

Charges Related to Wind-Down Costs and Certain Asset Impairments

In Q4 2024, Emera recognized $32 million ($26 million after-tax, or $0.09 per common share) in wind-down costs and certain asset impairments, primarily at Block Energy. These were recorded in "Other Income, net" and "Impairment Charges" on the Consolidated Statements of Income and included mainly in the Other segment.

Gain on Sale of LIL

On June 4, 2024, Emera completed the sale of its LIL equity interest. A gain on sale of $182 million after transaction costs ($107 million, after tax and transaction costs, or $0.37 per common share), was recognized in “Other Income, net” on the Consolidated Statements of Income in Q2 2024 and included in the Other segment. In Q4 2024, Emera recognized a $22 million ($0.08 per common share) tax benefit related to the reversal of a prior year valuation allowance. A portion of the taxable capital gain on the sale of the LIL equity interest was offset by prior year loss carryforwards, of which the tax benefit had been subject to a valuation allowance as at December 31, 2023. This tax benefit was recorded in “Income Tax (Recovery) Expense” on the Consolidated Statements of Income in Q4 2024 and included in the Other segment. For further details on the transaction, refer to the “Other Developments” section.

Charges Related to the Pending Sale of NMGC

In Q3 2024, Emera recognized non-cash goodwill and other impairment charges of $221 million ($206 after-tax, or $0.72 per common share) related to the NMGC reporting unit. These charges were recorded in “Impairment charges” on the Consolidated Statements of Income and included in the Other and Gas Utilities and Infrastructure segments, respectively. For further details on the pending sale of NMGC, refer to the “Other Developments” section. For further details on the non-cash goodwill impairment charge, refer to note 23 in the consolidated financial statements.

Additionally, in Q3 2024, Emera recorded a loss of $25 million ($19 million after-tax, or $0.06 per common share) in estimated transaction costs related to the pending sale of NMGC. These transaction costs were recorded in “Other Income, net” on the Consolidated Statement of Income and included in the Other segment. For further details, refer to the “Other Developments” section.

Earnings Impact of MTM Loss, After-Tax

Quarter-to-date the 2023 MTM gain, after-tax, of $114 million decreased $260 million to a $146 million MTM loss, after-tax, for the same period in 2024. For the year ended, the 2023 MTM gain, after-tax, of $169 million decreased $460 million to a $291 million MTM loss, after-tax, for the same period in 2024. These decreases were primarily due to changes in existing positions, partially offset by lower amortization of gas transportation at Emera Energy Services (“EES”).

Consolidated Financial Highlights

For the millions of dollars	Three months ended December 31		Year ended December 31		
Adjusted net income	**2024**	2023	**2024**	2023	2022
Florida Electric Utility	**$ 120**	$ 115	**$ 644**	$ 627	$ 596
Canadian Electric Utilities	**77**	68	**232**	247	222
Gas Utilities and Infrastructure	**87**	59	**267**	214	221
Other Electric Utilities	**21**	4	**48**	35	29
Other	**(59)**	(71)	**(342)**	(314)	(218)
Adjusted net income	**$ 246**	$ 175	**$ 849**	$ 809	$ 850
Gain on sale of LIL, after-tax	**22**	-	**129**	-	-
Financing structure wind-up	**58**	-	**58**	-	-
Charges related to wind-down costs and certain asset impairments, after-tax	**(26)**	-	**(26)**	-	-
Charges related to the pending sale of NMGC, after-tax	**-**	-	**(225)**	-	-
MTM (loss) gain, after-tax	**(146)**	114	**(291)**	169	175
GBPC impairment charge	**-**	-	**-**	-	(73)
NSPML unrecoverable costs	**-**	-	**-**	-	(7)
Net income attributable to common shareholders	**$ 154**	$ 289	**$ 494**	$ 978	$ 945

The following table highlights significant changes in adjusted net income from 2023 to 2024:

For the millions of dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2023	**$ 175**	**$ 809**
Operating Unit Performance		
Increased earnings at NSPI due to increased income tax recovery, partially offset by higher operating, maintenance and general expenses ("OM&G") due primarily to a lower storm cost deferral	31	19
Increased earnings quarter-over-quarter at Other Electric Utilities primarily due to the timing of recovery of fuel costs and lower OM&G. Year-over-year increased primarily due to higher sales volumes, partially offset by higher OM&G	17	13
Increased earnings quarter-over-quarter at NMGC due to higher revenue from new base rates, partially offset by higher income tax expense. Decreased earnings year-over-year due to lower asset optimization revenue, partially offset by higher revenue from new base rates	14	(4)
Increased earnings at PGS due to higher revenue from new base rates and customer growth, partially offset by increased interest expense, depreciation, OM&G, and income tax expense	11	58
Increased earnings at TEC due to higher revenues from customer growth and new base rates, and the impact of a weaker CAD, partially offset by higher OM&G, and depreciation. Year-over-year increased earnings also due to lower income tax expense and lower interest expense, partially offset by unfavourable weather	5	17
Decreased earnings year-over-year at EES due to favourable hedging opportunities in Q1 2023 and less favourable market conditions in 2024	(3)	(16)
Decreased earnings at Bear Swamp primarily due to the recognition of investment tax credits in 2023	(13)	(20)
Decreased income from equity investments due to the sale of LIL equity interest	(16)	(32)
Corporate		
Decreased deferred income tax asset valuation allowance due to utilization of tax loss carryforwards	36	39
Increased income tax recovery due to increased loss before provision for income taxes	15	20
Increased interest expense due to the impact of a weaker CAD on USD interest expense, increased total Corporate debt and increased interest rates	(9)	(38)
Increased OM&G quarter-over-quarter primarily due to the timing difference in the valuation of long-term incentive expense and related hedges	(16)	(1)
Other Variances	(1)	(15)
Adjusted net income – 2024	**$ 246**	**$ 849**

For the millions of dollars		Year ended December 31	
	2024	2023	2022
Operating cash flow before changes in working capital	**$ 2,194**	$ 2,336	$ 1,147
Change in working capital	**452**	(95)	(234)
Operating cash flow	**$ 2,646**	$ 2,241	$ 913
Investing cash flow	**$ (2,218)**	$ (2,917)	$ (2,569)
Financing cash flow	**$ (818)**	$ 939	$ 1,555

For further discussion of cash flow, refer to the "Consolidated Cash Flow Highlights" section.

As at millions of dollars		2024		2023		December 31 2022
Total assets	$	**42,951**	$	39,480	$	39,742
Total long-term debt (including current portion) (1)	$	**18,407**	$	18,365	$	16,318

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As at December 31, 2024, NMGC's assets and liabilities were classified as held for sale and are excluded from this table. For further details, refer to the 'Other Developments' section and note 4 in the consolidated financial statements.

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended December 31 2024	2023	Variance	Year ended December 31 2024	2023	Variance	Year ended December 31 2022
Operating revenues	**$ 1,763**	$ 1,972	$ (209)	**$ 7,200**	$ 7,563	$ (363)	$ 7,588
Operating expenses	**1,524**	1,467	(57)	**6,120**	5,769	(351)	5,959
Income from operations	**$ 239**	$ 505	$ (266)	**$ 1,080**	$ 1,794	$ (714)	$ 1,629
Other (expense) income, net	**$ (29)**	$ 51	$ (80)	**$ 203**	$ 158	$ 45	$ 145
Interest expense, net	**$ 248**	$ 241	$ (7)	**$ 973**	$ 925	$ (48)	$ 709
Income tax (recovery) expense	**$ (199)**	$ 51	$ 250	**$ (159)**	$ 128	$ 287	$ 185
Net income attributable to common shareholders	**$ 154**	$ 289	$ (135)	**$ 494**	$ 978	$ (484)	$ 945
Adjusted net income	**$ 246**	$ 175	$ 71	**$ 849**	$ 809	$ 40	$ 850
Weighted average shares of common stock outstanding (in millions)	**294.1**	277.7	16.4	**289.1**	273.6	15.5	265.5
EPS – basic	**$ 0.52**	$ 1.04	$ (0.52)	**$ 1.71**	$ 3.57	$ (1.86)	$ 3.56
EPS – diluted	**$ 0.52**	$ 1.04	$ (0.52)	**$ 1.71**	$ 3.57	$ (1.86)	$ 3.55
Adjusted EPS – basic	**$ 0.84**	$ 0.63	$ 0.21	**$ 2.94**	$ 2.96	$ (0.02)	$ 3.20
Adjusted EBITDA	**$ 753**	$ 705	$ 48	**$ 3,048**	$ 2,910	$ 138	$ 2,687
Dividends per common share declared	**$ 0.7250**	$ 0.7175	$ 0.0075	**$ 2.8775**	$ 2.7875	$ 0.0900	$ 2.6775
Dividends per first preferred shares declared:							
Series A				**$ 0.5456**	$ 0.5456	$ -	$ 0.5456
Series B				**$ 1.6966**	$ 1.5583	$ 0.1383	$ 0.6869
Series C				**$ 1.6085**	$ 1.2873	$ 0.3212	$ 1.1802
Series E				**$ 1.1250**	$ 1.1250	$ -	$ 1.1250
Series F				**$ 1.0505**	$ 1.0505	$ -	$ 1.0505
Series H				**$ 1.5810**	$ 1.3140	$ 0.2670	$ 1.2250
Series J				**$ 1.0625**	$ 1.0625	$ -	$ 1.0625
Series L				**$ 1.1500**	$ 1.1500	$ -	$ 1.1500

Operating Revenues

For Q4 2024, operating revenues decreased $209 million compared to Q4 2023 and, excluding decreased MTM gain of $291 million, increased $82 million. For the year ended December 31, 2024, operating revenues decreased $363 million compared to 2023 and, excluding decreased MTM gain of $559 million, increased $196 million. The increases were due to new rates at PGS, NSPI, TEC and NMGC; the impact of a weaker CAD; and increased customer growth at TEC and PGS. The increases were partially offset by lower fuel recovery clause and storm surcharge revenue (offset in OM&G) at TEC; and lower fuel revenue at NMGC. Year-over-year increase was also due to a change in the fuel cost recovery methodology for an industrial customer in 2023 at NSPI (offset in fuel for generation and purchased power).

Operating Expenses
For Q4 2024, operating expenses increased $57 million compared to Q4 2023, and, excluding charges related to wind-down costs and certain asset impairments of $4 million, increased $53 million. For the year ended December 31, 2024, operating expenses increased $351 million compared to 2023, and excluding the goodwill and other impairment charges primarily related to the pending sale of NMGC of $225 million, increased $126 million due to higher depreciation at TEC and PGS; the impact of a weaker CAD; higher OM&G due to timing of deferred clause recoveries at PGS and TEC; lower storm cost deferral and higher demand side management program costs at NSPI; and higher labour costs at PGS. This was partially offset by lower natural gas prices at NMGC, PGS and TEC and lower storm cost recognition at TEC (offset in revenue). Year-over-year increase was also due to a change in fuel cost recovery for an industrial customer in 2023 at NSPI (offset in revenue).

Other Income, Net
For Q4 2024, other income, net decreased $80 million compared to Q4 2024 due to charges related to wind-down costs and certain asset impairments and higher FX losses.

For the year ended December 31, 2024, other income, net increased $45 million compared to the same period in 2023 due to the gain on sale of LIL, after transaction costs, partially offset by higher FX losses, charges related wind-down costs and certain asset impairments, transaction costs related to the pending sale of NMGC, and lower interest income.

Interest Expense, Net
For Q4 2024, interest expense, net increased $7 million and for the year ended December 31,2024, increased $48 million compared to the same periods in 2023 due to the impact of a weaker CAD on USD interest expense, increased borrowings to support ongoing operations and higher interest rates.

Income Tax (Recovery) Expense
For Q4 2024, income tax recovery increased $250 million compared to Q4 2023 due to decreased income before provision for income taxes, decreased deferred income tax asset valuation allowance and recognition of tax benefits associated with denied interest and financing expenses.

For the year ended December 31, 2024, income tax recovery increased $287 million compared to 2023 due to decreased income before provision for income taxes (excluding the gain on sale of LIL and charges related to the pending sale of NMGC), decreased deferred income tax asset valuation allowance and recognition of tax benefits associated with denied interest and financing expenses. This increased recovery was partially offset by the net tax impact of the gain on sale of LIL and charges related to the pending sale of NMGC.

Net Income and Adjusted Net Income
For Q4 2024, net income attributable to common shareholders compared to Q4 2023, was favourably impacted by the $58 million tax benefit related to a specific financing structure and its wind-up and the $22 million valuation allowance reversal related to the gain on sale of LIL, and unfavourably impacted by the $26 million charges related to wind-down costs and certain asset impairments, and the $260 million decrease in MTM gains. Excluding these impacts, adjusted net income increased $71 million, primarily due to increased earnings at NSPI, Other Electric Utilities, NMGC, PGS, and TEC, and increased Corporate income tax recovery. This was partially offset by lower equity earnings from LIL; increased Corporate OM&G due to timing of long-term incentive expenses and related hedges; increased Corporate interest expense; and decreased earnings at Emera Energy.

For the year ended December 31, 2024, net income attributable to common shareholders, compared to the same period in 2023, was favourably impacted by the $129 million gain on sale of LIL, and the $58 million tax benefit related to a specific financing structure and its wind-up and unfavourably impacted by the $26 million in charges related to wind-down costs and certain asset impairments, $225 million in charges related to the pending sale of NMGC, and the $460 million decrease in MTM gains. Excluding these changes, adjusted net income increased $40 million. The increase was primarily due to increased earnings at PGS, NSPI, TEC, and Other Electric Utilities, and increased Corporate income tax recovery. This was partially offset by increased Corporate interest expense; lower equity earnings from LIL; and decreased earnings at Emera Energy.

EPS – Basic and Adjusted EPS – Basic

For Q4 2024, EPS – basic was lower than in Q4 2023 due to the impact of decreased earnings, as discussed above, and an increase in weighted average shares outstanding. Adjusted EPS – basic was higher in Q4 2024, compared to Q4 2023, due to increased adjusted earnings as discussed above, partially offset by an increase in weighted average shares outstanding.

For the year ended December 31, 2024, EPS – basic was lower than in 2023 due to the impact of an increase in weighted average shares outstanding and decreased earnings, as discussed above. Adjusted EPS – basic was lower in 2024, compared to 2023, due to the impact of an increase in weighted average shares outstanding, partially offset by increased adjusted earnings, as discussed above.

Effect of Foreign Currency Translation

Emera operates in the United States ("US"), Canada and various Caribbean countries and, as such, generates revenues and incurs expenses denominated in local currencies which are translated into CAD for financial reporting. Changes in translation rates, particularly in the value of the USD against the CAD, can positively or adversely affect results.

Results of foreign operations are translated at the weighted average rate of exchange, and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates on net income attributable to common shareholders for 2024 and 2023 are as follows:

	Three months ended December 31				Year ended December 31			
		2024		2023		**2024**		2023
Weighted average CAD/USD	**$**	**1.37**	$	1.36	**$**	**1.36**	$	1.35
Period end CAD/USD exchange rate	**$**	**1.44**	$	1.32	**$**	**1.44**	$	1.32

The table below includes Emera's significant segments whose contributions to adjusted net income are recorded in USD currency:

For the	Three months ended December 31				Year ended December 31			
millions of USD		**2024**		2023		**2024**		2023
Florida Electric Utility (1)	**$**	**85**	$	85	**$**	**470**	$	466
Gas Utilities and Infrastructure (2)(3)		**56**		41		**178**		142
Other Electric Utilities		**15**		3		**35**		26
Other segment (4)(5)		**(33)**		(18)		**(131)**		(95)
Total (1)(3)(5)	**$**	**123**	$	111	**$**	**552**	$	539

(1) Excludes $2 million USD, after-tax, in other impairment charges for the three months and year ended December 31, 2024.
(2) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(3) Excludes $6 million USD, after-tax, in other impairment charges associated with the pending sale of NMGC for the year ended December 31, 2024.
(4) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(5) Excludes $84 million USD in MTM losses, after-tax, for the three months ended December 31, 2024 (2023 – $73 million USD MTM gain, after-tax) and $189 million in USD MTM losses, after-tax, for the year ended December 31, 2024 (2023 – $116 million USD MTM gain, after-tax).

Weakening of the CAD increased adjusted net income by $2 million in Q4 2024 and $5 million for the year ended December 31, 2024, compared to the same periods in 2023. Impacts of the changes in the translation of the CAD include the impacts of Corporate FX hedges used to mitigate translation risk of USD earnings in the Other segment.

The translation impact of a weaker CAD on USD earnings was more than offset by the realized and unrealized losses on FX hedges used to mitigate translation risk of USD earnings, resulting in a $29 million decrease to net income in Q4 2024 and $35 million decrease to net income for the year ended December 31, 2024, compared to the same periods in 2023.

BUSINESS OVERVIEW AND OUTLOOK

Florida Electric Utility

The Florida Electric Utility segment consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. TEC has $13 billion USD of assets and approximately 855,000 customers at December 31, 2024. TEC owns 6,620 megawatts ("MW") of generating capacity, of which 73 per cent is natural gas fired, 20 per cent is solar and 7 per cent is coal. TEC also owns 2,192 kilometres of transmission facilities and 20,693 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Beginning in 2025, TEC's approved regulated ROE range is 9.50 per cent to 11.50 per cent (2024 – 9.25 per cent to 11.25 per cent) based on an allowed equity capital structure of 54 per cent (2024 – 54 per cent). An ROE of 10.50 per cent (2024 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

TEC anticipates earning within its ROE range in 2025. As a result of new base rates effective January 1, 2025, TEC's 2025 USD earnings are expected to be higher than in 2024. Normalizing 2024 for weather, TEC's sales volumes in 2025 are projected to be higher than in 2024 due to customer growth. TEC expects customer growth rates in 2025 to be comparable to 2024, reflective of the expected economic growth in Florida.

On April 2, 2024, TEC filed a rate case with the FPSC for new base rates. On December 3, 2024, the FPSC rendered a decision which includes annual base rate increases of $185 million USD in 2025 and adjustments of $87 million USD and $9 million USD in 2026 and 2027, respectively. The rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and other resiliency and reliability projects. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital and the allowed regulatory ROE range is 9.50 per cent to 11.50 per cent with a 10.50 per cent midpoint. On February 3, 2025, the FPSC issued the final order approving the decision, effective January 1, 2025. On February 18, 2025, a motion for reconsideration on certain aspects of the rate case order was filed with the FPSC. TEC will respond to this motion in February 2025. TEC expects the FPSC to reach a final decision on the motion in Q2 2025.

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

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

As at December 31, 2024, total restoration costs charged to the storm reserve account have exceeded the storm reserve balance (for additional details on the storm reserve, refer to note 7 in Emera's consolidated financial statements) and therefore $377 million USD has been deferred as a regulatory asset for future recovery. On February 4, 2025, the FPSC approved TEC's petition filed on December 27, 2024 for the recovery of $466 million USD for costs associated with Hurricane Idalia, Hurricane Debby, Hurricane Helene and Hurricane Milton and the associated interest to replenish the storm reserve over an 18-month recovery period beginning in March 2025. The amount of cost-recovery is subject to a true-up mechanism with the FPSC.

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

In 2025, capital investment in the Florida Electric Utility segment is expected to be $1.7 billion USD (2024 – $1.4 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization, storm hardening investments, building resilience and energy storage.

Canadian Electric Utilities

The Canadian Electric Utilities segment includes NSPI and NSPML. NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia. NSPML is a 100 per cent equity interest in the Maritime Link Project ("Maritime Link"), a transmission project between the island of Newfoundland and Nova Scotia.

On June 4, 2024, Emera completed the sale of its LIL equity interest. For further information, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

NSPI

With $7.1 billion of assets and approximately 557,000 customers at December 31, 2024, NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind, or solar; 7 per cent is petroleum coke ("petcoke") and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPPs") and community feed-in tariff ("COMFIT") participants, which own 533 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Newfoundland and Labrador Hydro's ("NLH") Nova Scotia Block ("NS Block") delivery obligations, as discussed below. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities.

NLH is obligated to provide NSPI with approximately 900 Gigawatt hours ("GWh") of energy annually over 35 years. In addition, for the first five years of the NS Block, NLH is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from NLH through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from NLH for up to 1.8 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

NSPI'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 40 per cent of approved rate base.

NSPI anticipates earning below its allowed ROE range in 2025. NSPI expects earnings in 2025 to be consistent with 2024. Sales volumes are expected to be higher in 2025 than 2024.

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

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

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

On June 13, 2024, the UARB approved $238 million of capital investment, including AFUDC, for the Battery Energy Storage System Project. The project is comprised of three 50 MW, four-hour battery facilities. Two facilities are anticipated to be in-service in late 2025 and the third facility in 2026.

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

In 2025, capital investment, including AFUDC, is expected to be $480 million (2024 – $487 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Regulations

NSPI is subject to environmental laws and regulations set by both the Government of Canada and the Province. NSPI continues to work with both levels of government to comply with these laws and regulations to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated compliance will be recoverable under NSPI's regulatory framework. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI's operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the "Enterprise Risk and Risk Management" section. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Clean Electricity Regulations (“CER”):
On December 17, 2024, Environment and Climate Change Canada released a finalized version of the CER. The CER establish performance standards to further limit greenhouse gas (“GHG”) emissions from fossil fuel-generated electricity starting in 2035 and help facilitate the Government of Canada’s intention of achieving a net-zero electricity grid by 2050. Compliance with the finalized version of the CER is not anticipated to require significant capital investment incremental to achieve the 2030 targets as NSPI’s planned capital investment during this period is driven by the Province’s goals to transition off coal and reach 80 per cent renewable electricity sales by 2030.

Nova Scotia Energy Reform Act:
On April 5, 2024, the Province enacted Bill 404 - Energy Reform (2024) Act. The legislation enacted the Energy and Regulatory Board Act, which established the Nova Scotia Energy Board (“NSEB”). The NSEB is a new board which will regulate energy and utility entities in Nova Scotia, with a mandate of increased focus on meeting energy transition demands. The legislation also enacts the More Access to Energy Act, which provides for the establishment of and phased transition to the Nova Scotia Independent Energy System Operator. NSPI is fully engaged in supporting the Province on these initiatives.

RER:
On May 26, 2023, NSPI initiated an appeal, through a proceeding with the UARB, of the $10 million penalty levied on NSPI by the Province for non-compliance with the RER compliance period ending in 2022. The hearing for the matter is currently scheduled for June 2025.

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.

Equity earnings from NSPML in 2025 are expected to consistent with 2024. The NSPML investment is recorded as “Investments subject to significant influence” on Emera’s Consolidated Balance Sheets.

The Maritime Link assets entered service on January 15, 2018, enabling the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. NLH’s NS Block delivery obligations commenced on August 15, 2021, and the NS Block will be delivered over the next 35 years pursuant to the project agreements.

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

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

NSPML does not anticipate any significant capital investment in 2025.

Gas Utilities and Infrastructure

The Gas Utilities and Infrastructure segment includes PGS, NMGC, SeaCoast, Brunswick Pipeline and Emera's equity investment in M&NP. PGS is a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida. NMGC is an intrastate regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a regulated intrastate natural gas transmission company offering services in Florida. Brunswick Pipeline is a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern US.

On August 5, 2024, Emera announced an agreement to sell NMGC. The transaction is expected to close in late 2025, subject to certain approvals, including approval by the NMPRC. As a result of the pending sale, NMGC's assets and liabilities were classified as held for sale as of Q3 2024. For more information on the pending transaction, refer to the "Other Developments" section.

PGS

With $3.1 billion USD of assets and approximately 508,000 customers, the PGS system includes 25,240 kilometres of natural gas mains and 14,530 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2024.

The approved ROE range for PGS is 9.15 per cent to 11.15 per cent based on an allowed equity capital structure of 54.7 per cent. An ROE of 10.15 per cent is used for the calculation of return on investments for clauses.

PGS anticipates earning near the bottom of its allowed ROE range in 2025 as a result of the continued investments across Florida to maintain reliability and service new customers. Capital investments are expected to outpace revenue growth. USD earnings for 2025 are expected to be consistent with 2024 primarily due to higher operating costs and depreciation driven by ongoing capital investments to support customer demand and system needs.

On January 30, 2025, PGS notified the FPSC of its intent to seek a base rate increase effective January 2026, reflecting a revenue requirement of approximately $90 to $110 million USD and subsequent year adjustment for 2027 of approximately $25 to $40 million USD. PGS' proposed rates support on-going growth in Florida and a continued commitment to delivering safe and reliable service to PGS customers. The filing range amounts are estimates until PGS files its detailed case in March 2025. The FPSC is scheduled to hear the case in Q3 2025 with a decision expected by the end of 2025.

In 2025, capital investment, including AFUDC, is expected to be approximately $360 million USD (2024 – $323 million USD). PGS will make investments to maintain the reliability of their systems and support customer growth.

NMGC

With $1.5 billion USD of assets and approximately 550,000 customers, NMGC's system includes approximately 2,405 kilometres of transmission pipelines and 17,810 kilometres of distribution pipelines. Annual natural gas throughput was approximately 1 billion therms in 2024.

The approved ROE for NMGC is 9.375 per cent, on an allowed equity capital structure of 52 per cent.

NMGC's USD earnings contributions to Emera in 2025 are expected to be lower than in 2024 as a result of the pending sale of NMGC that is currently expected to close in October 2025.

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

Other Electric Utilities

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, and an equity investment in Lucelec on the island of St. Lucia.

Other Electric Utilities' USD earnings in 2025 are expected to be consistent with the prior year.

In 2025, capital investment in the Other Electric Utilities segment is expected to be approximately $140 million USD, including AFUDC (2024 – $59 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

BLPC

With $538 million USD of assets and approximately 135,000 customers, BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. BLPC owns approximately 188 kilometres of transmission facilities and 3,989 kilometres of distribution facilities. BLPC's approved regulated return on rate base is 10 per cent.

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

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

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

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.

GBPC

With $340 million USD of assets and approximately 19,500 customers, GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 994 kilometres of distribution facilities. GBPC's approved regulatory return on rate base is 8.52 per cent.

On August 1, 2024, as required by the GBPA Operating Protocol and Regulatory Framework Agreement, GBPC filed a rate plan proposal. Review of the rate application is expected to be completed in 2025.

On June 1, 2024, the Electricity Act, 2024 took effect. The legislation purports to remove the jurisdiction of the GBPA over GBPC and to have the Utilities Regulation and Competition Authority, another Bahamian regulator, regulate GBPC. The GBPA has opposed the legislated removal of its regulatory authority over GBPC, citing conflict with the Hawksbill Creek Agreement, the 1955 agreement with the Bahamian government that provided for the development and administration of the Freeport area. Management expects the matter of regulatory jurisdiction over GBPC to be the subject of legal proceedings, however, does not foresee that the legislation or the outcome of such proceedings will have a material impact to Emera.

Other

The Other segment includes business operations that in a normal year are below the required threshold for reporting as separate segments; and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments.

Business operations in the Other segment include Corporate; Emera Energy Services (EES), a physical energy marketing and trading business; a 50 per cent joint venture interest in Bear Swamp, a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts; and Block Energy. In Q4 2024, Block Energy initiated the process to wind-up operations.

Corporate items included are certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings and interest expense on corporate debt in both Canada and the US. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera's subsidiaries and investments.

Earnings from EES are generally dependent on market conditions. In particular, volatility in natural gas and electricity markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 usually providing the greatest opportunity for earnings. EES is generally expected to deliver annual adjusted net income of $15 to $30 million USD.

The adjusted net loss from the Other segment is expected to be lower in 2025 than 2024, due primarily to the wind-up of Block Energy in 2024.

The Other segment does not anticipate any significant capital investment in 2025.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2023 and December 31, 2024 include:

millions of dollars	Total Increase (Decrease)	Increase (Decrease) due to held for sale classification (1)	Other Increase (Decrease)	Explanation of Other Increase (Decrease)
Assets				
Cash and cash equivalents	**$ (371)**	**$ (8)**	**$ (363)**	Decreased due to investment in PP&E, net repayments on committed credit facilities at Corporate and NSPI, repayment of short-term debt at TEC, retirement of long-term debt at Emera, TEC and New Mexico Gas Intermediate, Inc ("NMGI"), and dividends paid on Emera common stock. These were partially offset by cash from operations, proceeds from debt issuances at TEC and EUSHI Finance, Inc. ("EUSHI Finance"), proceeds received on the sale of the LIL equity interest and proceeds from common shares issued
Derivative instruments (current and long-term)	**(74)**	**(1)**	**(73)**	Decreased due to reversal of 2023 contracts at EES, partially offset by higher commodity prices at NSPI
Regulatory assets (current and long-term)	**322**	**(34)**	**356**	Increased due to higher storm costs recovery clause assets at TEC and NSPI, the effect of FX translation of Emera's non-Canadian affiliates, and reclassification of early retired plant from PP&E to a regulatory asset at TEC. These were partially offset by decreased FAM balance at NSPI due to the NSPML refund, and decreased fuel clause recovery balance at TEC due to higher over-recoveries
Receivables and other assets (current and long-term)	**70**	**(150)**	**220**	Increased due to higher cash collateral positions on derivative instruments and increased trade receivables as a result of higher commodity prices at EES, and the effect of FX translation of Emera's non-Canadian affiliates. These were partially offset by lower gas transportation assets at EES and lower trade receivables at TEC
Assets held for sale (current and long-term), net of liabilities	**973**	**973**	**-**	
PP&E, net of accumulated depreciation and amortization	**1,792**	**(1,828)**	**3,620**	Increased due to capital additions in excess of depreciation and the effect of FX translation of Emera's non-Canadian affiliates, partially offset by a reclassification of early retired plant to TEC capital cost recovery regulatory asset
Investments subject to significant influence	**(748)**	**-**	**(748)**	Decreased primarily due to sale of LIL equity interest
Goodwill	**(13)**	**(303)**	**290**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates, partially offset by the non-cash impairment charge recognized primarily related to NMGC

(1) On August 5, 2024, Emera announced the sale of NMGC. As at December 31, 2024 NMGC's assets and liabilities were classified as held for sale. For further details, refer to the 'Other Developments' section and note 3 in the consolidated financial statements.

millions of dollars	Total Increase (Decrease)	Increase (Decrease) due to held for sale classification (1)	Other Increase (Decrease)	Explanation of Other Increase (Decrease)
Liabilities and Equity				
Short-term debt and long-term debt (including current portion)	**$ 9**	**$ (742)**	**$ 751**	Increased due the effect of FX translation of Emera's non-Canadian affiliates, proceeds from long-term debt issuance at TEC, and issuance of junior subordinated notes at EUSHI Finance. These were partially offset by repayment of Emera's committed credit facilities using the LIL transaction proceeds, repayment of short-term debt at TEC and NSPI, and retirement of long-term debt at Corporate, TEC, and NMGI
Accounts payable	**538**	**(131)**	**669**	Increased due to storm cost payable at TEC, the effect of FX translation of Emera's non-Canadian affiliates, and increased commodity prices at EES
Deferred income tax liabilities, net of deferred income tax assets	**(205)**	**(167)**	**(38)**	No significant change after removing impact of held for sale classification
Derivative instruments (current and long-term)	**113**	**(1)**	**114**	Increased due to new contracts in 2024 and changes in existing positions at EES, higher FX forward liability at Corporate due to changes in the FX hedges, partially offset by higher commodity prices and settlements of derivative instruments at NSPI
Regulatory liabilities (current and long-term)	**108**	**(284)**	**392**	Increased due to effect of FX translation of Emera's non-Canadian affiliates and recognition of fuel cost recovery liabilities at TEC and NSPI due to over-recovery of fuel costs
Other liabilities (current and long-term)	**152**	**(34)**	**186**	Increased due the effect of FX translation of Emera's non-Canadian affiliates and higher accrued interest on long-term debt at NSPI
Common stock	**580**	**-**	**580**	Increased due to shares issued
Accumulated other comprehensive income	**956**	**-**	**956**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates
Retained earnings	**(335)**	**-**	**(335)**	Decreased due to dividends paid in excess of net income

(1) On August 5, 2024, Emera announced the sale of NMGC. As at December 31, 2024 NMGC's assets and liabilities were classified as held for sale. For further details, refer to the 'Other Developments' section and note 3 in the consolidated financial statements.

OTHER DEVELOPMENTS

Canadian Tax Legislation Changes

On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the EIFEL regime, which is effective January 1, 2024. EIFEL applies to limit a company's net interest and financing expense deduction to no more than 30 per cent of EBITDA for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely. During 2024, the Company incurred $185 million of interest and financing expenses in connection with a specific financing structure. The interest and financing expenses related to the financing structure as well as $88 million of other interest and financing expenses are expected to be denied under the EIFEL regime. It was determined that the Company is more likely than not to realize the tax benefit of the denied interest and financing expenses in future periods and therefore a $79 million deferred income tax asset has been recorded as at December 31, 2024.

Pending Sale of NMGC

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

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

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

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

Increase in Common Dividend

On September 18, 2024, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.90 from $2.87 per common share. The first payment was effective November 15, 2024.

Sale of LIL Equity Interest

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

Appointments

Board of Directors

Effective February 21, 2025, Karen Sheriff was appointed Chair of the Emera Board of Directors, succeeding Jackie Sheppard. Ms. Sheriff joined the Emera Board of Directors in February 2021 and since that time has served as a member of the Management Resources and Compensation Committee, the Risk and Sustainability Committee as well as Chair of the Nominating and Corporate Governance Committee.

Effective June 26, 2024, Carla Tully joined the Emera Board of Directors. Ms. Tully is the former Chief Executive Officer and Co-Founder of Earthrise Energy, PBC, an energy transition company. She also previously served as Executive Vice President and Managing Director of Renewable Energy at MAP Energy and held various senior leadership roles with AES Corporation.

Effective March 6, 2024, Brian J. Porter joined the Emera Board of Directors. Mr. Porter is the former President and Chief Executive Officer of The Bank of Nova Scotia (Scotiabank), a global bank operating in Canada and the Americas.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

For the millions of USD (except as indicated)	Three months ended December 31 **2024**	 2023	Year ended December 31 **2024**	 2023
Operating revenues – regulated electric	**$ 582**	$ 613	**$ 2,526**	$ 2,637
Regulated fuel for generation and purchased power	**$ 151**	$ 162	**$ 622**	$ 682
Contribution to consolidated adjusted net income	**$ 85**	$ 85	**$ 470**	$ 466
Contribution to consolidated adjusted net income - CAD	**$ 120**	$ 115	**$ 644**	$ 627
Charges related to wind-down costs and certain asset impairments, after-tax (1)	**$ (2)**	$ -	**$ (2)**	$ -
Contribution to consolidated net income	**$ 83**	$ 85	**$ 468**	$ 466
Contribution to consolidated net income – CAD	**$ 117**	$ 115	**$ 641**	$ 627
Average fuel costs in dollars per MWh	**$ 31**	$ 34	**$ 28**	$ 31

(1) Net of income tax recovery of $1 million for the three months and year ended December 31, 2024.

The impact of the change in the FX rate increased CAD earnings and adjusted earnings for the three months and year ended December 31, 2024, by $3 million and $10 million, respectively.

Net Income

Highlights of net income changes are summarized in the following table:

For the millions of USD		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2023	**$**	**85**	**$**	**466**
Decreased operating revenues primarily due to decreased fuel recovery clause revenue, lower storm surcharge revenue (offset in OM&G), and the unfavourable load impact of Hurricane Milton, partially offset by customer growth and new base rates. Revenues were also impacted by favourable weather of $10 million quarter-over-quarter, and unfavourable weather of $10 million year-over-year		(31)		(111)
Decreased fuel for generation and purchased power due to lower natural gas prices		11		60
Decreased OM&G due to lower storm cost recognition (offset in revenue), partially offset by the timing of deferred clause recoveries and higher solar operations, labour, and software maintenance costs		16		47
Increased depreciation and amortization due to additions to facilities and generation projects placed in service		(9)		(32)
Decreased interest expense year-over-year due to lower borrowings		-		7
Decreased state and municipal taxes due to lower retail sales tax, partially offset by higher property taxes		4		14
Decreased income tax expense year-over-year due to increased production tax credits related to solar facilities		-		18
Other		7		(1)
Contribution to consolidated net income – 2024	**$**	**83**	**$**	**468**

Operating Revenues – Regulated Electric

Annual electric revenues and sales volumes are summarized in the following table by customer class:

	Electric Revenues (millions of USD)				Electric Sales Volumes (Gigawatt hours ("GWh"))	
		2024		2023	**2024**	2023
Residential	**$**	**1,507**	$	1,711	**10,269**	10,307
Commercial		**686**		803	**6,481**	6,462
Industrial		**162**		203	**2,019**	2,082
Other (1)		**171**		(80)	**2,276**	2,194
Total	**$**	**2,526**	$	2,637	**21,045**	21,045

(1) Other includes regulatory deferrals related to clauses, sales to public authorities, off-system sales to other utilities.

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2024	2023
Natural gas	**18,027**	17,843
Solar	**2,250**	1,748
Purchased power	**1,569**	1,443
Coal	**32**	744
Total	**21,878**	21,778

TEC's fuel costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on first (renewable energy from solar or battery storage), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

Regulatory Environment

TEC is regulated by the FPSC and is also subject to regulation by the FERC. 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. For further details on TEC's regulatory environment, base rates and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Canadian Electric Utilities

On June 4, 2024, Emera completed the sale of its LIL equity interest. For further details on the transaction, refer to the "Other Developments" section.

For the millions of dollars (except as indicated)		Three months ended December 31 **2024**		2023		Year ended December 31 **2024**		2023
Operating revenues – regulated electric	**$**	**479**	$	439	**$**	**1,855**	$	1,671
Regulated fuel for generation and purchased power (1)	**$**	**(216)**	$	234	**$**	**509**	$	777
Contribution to consolidated net income	**$**	**77**	$	68	**$**	**232**	$	247
Average fuel costs in dollars per MWh (2)	**$**	**(73)**	$	81	**$**	**45**	$	70

(1) Regulated fuel for generation and purchased power includes NSPI's FAM deferral on the Consolidated Statements of Income, however, it is excluded in the segment overview.
(2) 2024 Average fuel costs include the $486 million NSPML Refund which decreased average fuel costs by $164 per MWh and $43 per MWh for the three months and year ended December 31, 2024, respectively. Average fuel costs for the year ended December 31, 2023 include reversal of the $166 million of the Nova Scotia Cap-and-Trade Program provision which decreased average fuel costs by $15 per MWh. For more information the NSPML Refund and the Nova Scotia Cap-and-Trade Program provision reversal, refer to note 7 in the consolidated financial statements.

Canadian Electric Utilities' contribution to consolidated net income is summarized in the following table:

For the millions of dollars		Three months ended December 31 **2024**		2023		Year ended December 31 **2024**		2023
NSPI	**$**	**71**	$	40	**$**	**160**	$	141
Equity investment in NSPML		**6**		12		**44**		46
Equity investment in LIL		**-**		16		**28**		60
Contribution to consolidated net income	**$**	**77**	$	68	**$**	**232**	$	247

Net Income

Highlights of net income changes are summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2023	**$ 68**	**$ 247**
Increased operating revenues at NSPI due to new rates. Year-over-year also due to changes in fuel cost recovery methodology for an industrial customer in 2023[(1)]	40	184
Decreased regulated fuel for generation and purchased power at NSPI due to the NSPML Refund[(1)] and decreased commodity prices, partially offset by change in generation mix and increased sales volumes. Year-over-year decrease was partially offset by the reversal of the Nova Scotia Cap-and-Trade Program provision[(1)] in 2023	450	268
Increased FAM deferral at NSPI primarily due to the NSPML Refund[(1)]. Year-over-year increase also due to changes in the fuel cost recovery methodology for an industrial customer in 2023 and under-recovery of fuel costs in 2023, partially offset by the reversal of the Nova Scotia Cap-and-Trade Program provision[(1)] in 2023	(484)	(428)
Increased OM&G due to a lower storm cost deferral, and higher demand side management program costs at NSPI	(8)	(24)
Decreased income from equity investments due to the sale of LIL	(16)	(34)
Increased income tax recovery at NSPI due to the utilization of tax loss carryforwards offset to a regulatory deferred income tax liability, partially offset by decreased tax deductions in excess of accounting depreciation related to property, plant and equipment	40	32
Other	(13)	(13)
Contribution to consolidated net income – 2024	**$ 77**	**$ 232**

(1) For more information on the changes in fuel cost recovery methodology for an industrial customer in 2023, the $486 million NSPML Refund, and the $166 million reversal of the Nova Scotia Cap-and-Trade Program provision, refer to note 7 in the consolidated financial statements.

NSPI

Operating Revenues – Regulated Electric

Annual electric revenues and sales volumes are summarized in the following tables by customer class:

	Electric Revenues (millions of dollars)		**Electric Sales Volumes (GWh)**	
	2024	2023	**2024**	2023
Residential	**$ 997**	$ 910	**5,096**	4,986
Commercial	**499**	463	**3,046**	3,053
Industrial	**276**	219	**2,217**	2,164
Other	**41**	41	**222**	239
Total	**$ 1,813**	$ 1,633	**10,581**	10,442

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2024	2023
Coal	**3,347**	3,086
Natural gas	**2,317**	1,946
Purchased power	**620**	881
Petcoke	**374**	553
Oil	**132**	145
Total non-renewables	**6,790**	6,611
Purchased power - IPP, COMFIT and imports	**3,464**	3,251
Wind, hydro and solar	**932**	1,149
Biomass	**140**	128
Total renewables	**4,536**	4,528
Total production volumes	**11,326**	11,139

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet. NSPI brings the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place, and the NS Block of energy, including the Supplemental Energy Block, which carries no additional fuel cost outside of the UARB approved annual assessments paid to NSPML for the use of the Maritime Link.

Generation mix may also be affected by plant outages, carbon pricing programs, including the Nova Scotia Output-Based Pricing System, availability of renewable generation, availability of energy from the NS Block, plant performance, and compliance with environmental regulations.

Regulatory Environment - NSPI

NSPI is a public utility as defined in the 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 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. For further details on NSPI's regulatory environment and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Gas Utilities and Infrastructure

On August 5, 2024, Emera announced an agreement to sell NMGC. The transaction is expected to close in late 2025, subject to certain approvals, including regulatory approval by the NMPRC. For more information on the pending transaction, refer to the “Other Developments” section.

For the millions of USD (except as indicated)	Three months ended December 31 **2024**	 2023	Year ended December 31 **2024**	 2023
Operating revenues – regulated gas (1)	**$ 317**	$ 290	**$ 1,160**	$ 1,114
Operating revenues – non-regulated	**3**	3	**15**	15
Total operating revenue	**$ 320**	$ 293	**$ 1,175**	$ 1,129
Regulated cost of natural gas	**$ 81**	$ 99	**$ 289**	$ 391
Contribution to consolidated adjusted net income	**$ 61**	$ 43	**$ 194**	$ 158
Contribution to consolidated adjusted net income – CAD	**$ 87**	$ 59	**$ 267**	$ 214
Charges related to the pending sale of NMGC, after-tax (2)	**$ -**	$ -	**$ (6)**	$ -
Contribution to consolidated net income	**$ 61**	$ 43	**$ 188**	$ 158
Contribution to consolidated net income – CAD	**$ 87**	$ 59	**$ 259**	$ 214

(1) Operating revenues – regulated gas includes $12 million of finance income from Brunswick Pipeline (2023 – $11 million) for the three months ended December 31, 2024 and $46 million (2023 – $46 million) for the year ended December 31 2024; however, it is excluded from the gas revenues and cost of natural gas analysis below.
(2) Includes an other impairment charge, net of income tax recovery of nil and $2 million for the three months and the year ended December 31, 2024, respectively.

Gas Utilities and Infrastructure's contribution to consolidated adjusted net income is summarized in the following table:

For the millions of USD	Three months ended December 31 **2024**	 2023	Year ended December 31 **2024**	 2023
PGS	**$ 28**	$ 21	**$ 120**	$ 79
NMGC	**23**	14	**39**	43
Other	**10**	8	**35**	36
Contribution to consolidated adjusted net income	**$ 61**	$ 43	**$ 194**	$ 158

Impact of the change in the FX rate increased CAD earnings and adjusted earnings for the three months and year ended December 31, 2024, by $3 million and $4 million respectively.

Net Income

Highlights of net income changes are summarized in the following table:

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2023	**$ 43**	**$ 158**
Increased gas revenues due to new base rates at PGS and NMGC, and customer growth at PGS, partially offset by lower fuel revenues at NMGC	27	54
Decreased asset optimization revenues at NMGC	-	(8)
Decreased cost of natural gas due to lower natural gas prices primarily at NMGC	18	102
Increased OM&G primarily due to the timing of deferred clause recoveries and higher labour cost at PGS	(5)	(31)
Increased depreciation primarily due to asset growth at PGS and the effect of reversal of accumulated depreciation in 2023 as a result of the 2021 rate case settlement at PGS	(13)	(39)
Increased interest expense, net year-over-year, primarily due to higher interest rates and increased borrowings to support ongoing operations and capital investments primarily at PGS	1	(15)
Increased income tax expense primarily due to increased income before provision for income taxes at PGS. Quarter-over-quarter increase also due to increased income before provision for income taxes at NMGC	(13)	(21)
Charges related to the pending sale of NMGC, after-tax	-	(6)
Other	3	(6)
Contribution to consolidated net income – 2024	**$ 61**	**$ 188**

Operating Revenues – Regulated Gas

Annual gas revenues and sales volumes are summarized in the following tables by customer class:

	Gas Revenues (millions of USD)		**Gas Volumes (millions of Therms)**	
	2024	2023	**2024**	**2023**
Residential	**$ 520**	$ 537	**410**	414
Commercial	**362**	315	**824**	839
Industrial (1)	**69**	69	**1,620**	1,615
Other (2)	**163**	147	**278**	266
Total (3)	**$ 1,114**	$ 1,068	**3,132**	3,134

(1) Industrial gas revenue includes sales to power generation customers.

(2) Other gas revenue includes off-system sales to other utilities and various other items.

(3) Total gas revenue excludes $46 million of finance income from Brunswick Pipeline (2023 – $46 million).

Regulated Cost of Natural Gas

PGS and NMGC purchase gas from various suppliers depending on the needs of their customers. In Florida, gas is delivered to the PGS distribution system through interstate pipelines on which PGS has firm transportation capacity for delivery by PGS to its customers. NMGC's natural gas is transported on major interstate pipelines and NMGC's intrastate transmission and distribution system for delivery to customers.

In Florida, natural gas service is unbundled for non-residential customers and residential customers who use more than 1,999 therms annually and elect the option. In New Mexico, NMGC is required, if requested, to provide transportation-only services for all customer classes. The commodity portion of bundled sales is included in operating revenues, at the cost of the gas on a pass-through basis, therefore no net earnings effect when a customer shifts to transportation-only sales.

Annual gas sales by type are summarized in the following table:

	Gas Volumes by Type (millions of Therms)	
	2024	2023
Transportation	**2,434**	2,461
System supply	**698**	673
Total	**3,132**	3,134

Regulatory Environments

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.

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.

For further information on PGS's and NMGC's regulatory environment and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Other Electric Utilities.

For the millions of USD (except as indicated)	Three months ended December 31 **2024**	2023	Year ended December 31 **2024**	2023
Operating revenues – regulated electric	**$ 107**	$ 104	**$ 413**	$ 390
Regulated fuel for generation and purchased power	**$ 55**	$ 57	**$ 215**	$ 204
Contribution to consolidated adjusted net income	**$ 15**	$ 3	**$ 35**	$ 26
Contribution to consolidated adjusted net income – CAD	**$ 21**	$ 4	**$ 48**	$ 35
Equity securities MTM (loss) gain	**$ (1)**	$ 2	**$ -**	$ 2
Contribution to consolidated net income	**$ 14**	$ 5	**$ 35**	$ 28
Contribution to consolidated net income – CAD	**$ 19**	$ 6	**$ 48**	$ 37
Electric sales volumes (GWh)	**323**	323	**1,307**	1,260
Electric production volumes (GWh)	**347**	345	**1,403**	1,362
Average fuel cost in dollars per MWh	**$ 159**	$ 165	**$ 153**	$ 150

The impact of the change in the FX rate increased CAD earnings and adjusted earnings by $1 million for the three months and year ended December 31, 2024.

Other Electric Utilities' contribution to consolidated adjusted net income is summarized in the following table:

For the millions of USD	Three months ended December 31 **2024**	2023	Year ended December 31 **2024**	2023
BLPC	**$ 13**	$ 4	**$ 27**	$ 18
GBPC	**3**	-	**11**	11
Other	**(1)**	(1)	**(3)**	(3)
Contribution to consolidated adjusted net income	**$ 15**	$ 3	**$ 35**	$ 26

Net Income

Highlights of net income changes are summarized in the following table:

For the millions of USD		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2023	**$**	**5**	**$**	**28**
Increased operating revenues quarter-over-quarter due to the timing of recovery of fuels costs. Year-over-year increased primarily due to higher sales volumes.		3		23
Increased fuel for generation and purchased power year-over-year due to higher sales volumes at BLPC.		2		(11)
Increased OM&G, year-over-year due to higher insurance premiums and increased generation maintenance costs at GBPC and BLPC.		1		(8)
Other		3		3
Contribution to consolidated net income – 2024	**$**	**14**	**$**	**35**

Regulatory Environments

BLPC is regulated by the FTC. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested.

GBPC is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base.

For further details on BLPC and GBPC's regulatory environments and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Other

For the millions of dollars		Three months ended December 31 **2024**		2023		Year ended December 31 **2024**		2023
Marketing and trading margin (1) (2)	**$**	**35**	$	35	**$**	**77**	$	96
Other non-regulated operating revenue		**10**		5		**32**		27
Total operating revenues – non-regulated	**$**	**45**	$	40	**$**	**109**	$	123
Contribution to consolidated adjusted net (loss) income	**$**	**(59)**	$	(71)	**$**	**(342)**	$	(314)
Gain on sale of LIL, after-tax (3)(4)		**22**		-		**129**		-
Financing structure wind-up		**58**		-		**58**		-
Charges related to wind-down costs and certain asset impairments, after-tax (5)		**(23)**		-		**(23)**		-
Charges related to the pending sale of NMGC, after-tax (6)		**-**		-		**(217)**		-
MTM (loss) gain, after-tax (7)		**(144)**		112		**(291)**		167
Contribution to consolidated net (loss) income	**$**	**(146)**	$	41	**$**	**(686)**	$	(147)

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.

(2) Marketing and trading margin excludes a MTM loss, pre-tax of $159 million in Q4 2024 (2023 – $131 million gain) and a MTM loss, pre-tax of $357 million for the year ended December 31, 2024 (2023 – $216 million gain).

(3) On June 4, 2024, Emera completed the sale of its LIL equity interest. For further details on the transaction, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

(4) Includes an income tax recovery of $22 million for the three months ended December 31, 2024 and net income tax expense of $53 million for the year ended December 31, 2024 (2023 – nil).

(5) Primarily relates to Block Energy, net of income tax recovery of $6 million for the year ended December 31, 2024 (2023 – nil).

(6) Includes a goodwill impairment charge of $210 million ($198 million after-tax) and transaction costs of $25 million ($19 million after-tax) for the year ended December 31, 2024 (2023 – nil).

(7) Net of income tax recovery of $57 million for the three months ended December 31, 2024 (2023 – $44 million expense) and $117 million recovery for the year ended December 31, 2024 (2023 – $68 million expense).

Other's contribution to consolidated adjusted net (loss) income is summarized in the following table:

For the millions of dollars		Three months ended December 31 **2024**		2023		Year ended December 31 **2024**		2023
Emera Energy:								
EES	**$**	**16**	$	19	**$**	**30**	$	46
Other		**(2)**		6		**2**		18
Corporate – see breakdown of adjusted contribution below		**(73)**		(91)		**(360)**		(356)
Block Energy		**-**		(4)		**(13)**		(18)
Other		**-**		(1)		**(1)**		(4)
Contribution to consolidated adjusted net (loss) income	**$**	**(59)**	$	(71)	**$**	**(342)**	$	(314)

Net Income

Highlights of net income changes are summarized in the following table:

For the millions of dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net (loss) income – 2023	**$**	**41**	**$**	**(147)**
Decreased marketing and trading margin year-over-year due to favourable hedging opportunities in Q1 2023 and less favourable market conditions in 2024, specifically lower natural gas prices and volatility		-		(19)
Increased OM&G quarter-over-quarter primarily due to the timing difference in the valuation of long-term incentive expense and related hedges		(18)		(2)
Increased interest expense due to the impact of a weaker CAD on USD interest expense, increased total debt and increased interest rates		(9)		(38)
Corporate FX losses on the translation of USD short-term debt balances		(5)		(9)
Decreased deferred income tax asset valuation allowance due to the utilization of tax loss carryforwards		36		39
Increased income tax recovery due to increased loss before provision for income taxes, partially offset by the recognition of investment tax credits related to Bear Swamp facility upgrades in 2023		3		4
Gain on sale of LIL, after-tax		22		129
Financing structure wind-up		58		58
Charges related to wind-down costs and certain asset impairments, after-tax		(23)		(23)
Charges related to the pending sale of NMGC, after-tax		-		(217)
The 2023 MTM gain, after-tax, decreased to a loss for the same periods in 2024 due to changes in existing positions, partially offset by lower amortization of gas transportation assets at EES		(254)		(457)
Other		3		(4)
Contribution to consolidated net (loss) income – 2024	**$**	**(146)**	**$**	**(686)**

Emera Energy

EES derives revenue and earnings from wholesale marketing and trading of natural gas and electricity within the Company's risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. EES purchases and sells physical natural gas and electricity, the related transportation and transmission capacity rights, and provides energy asset management services. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the US Southeast, Gulf Coast and Midwest, and Central Canadian and Alberta natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

EES' contribution to consolidated adjusted net income was $16 million in Q4 2024, compared to $19 million in Q4 2023; and $30 million ($21 million USD) for the year ended December 31, 2024, compared to $46 million ($33 million USD) for the same period in 2023. Market conditions in 2024 were less favourable compared to 2023 due to lower natural gas prices and volatility.

MTM Adjustments

Emera Energy's "Marketing and trading margin", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax (recovery) expense" are affected by MTM adjustments. Variance explanations of the MTM changes for this quarter and for the year are explained in the table above.

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities and natural gas producers in North America. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

Subsequent changes in gas price differentials, to the extent they are not offset by the accounting amortization of the gas transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial during the term of the contract, especially in the winter months of a contract when delivered volumes and market pricing are usually at peak levels. As a contract is realized, and volumes reduce, MTM volatility is expected to decrease. Ultimately, the gas transportation asset and the MTM adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM volatility resulting in gains and losses may also increase.

Emera Corporate has FX forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the FX rate result in MTM gains or losses are recorded in "Other income, net" on the Consolidated Statements of Income.

Corporate

Corporate's adjusted loss is summarized in the following table:

For the millions of dollars	Three months ended December 31 **2024**	2023	Year ended December 31 **2024**	2023
Operating expenses (1)	**$ (23)**	$ (7)	**$ (74)**	$ (73)
Interest expense	**(97)**	(88)	**(367)**	(329)
Income tax recovery	**76**	25	**170**	111
Preferred dividends	**(19)**	(18)	**(73)**	(66)
Other (2)(3)	**(10)**	(3)	**(16)**	1
Corporate adjusted net loss (4)(5)(6)(7)	**$ (73)**	$ (91)	**$ (360)**	$ (356)

(1) Operating expenses include OM&G and depreciation.
(2) Other includes realized gains and losses on FX hedges entered into to hedge USD denominated operating unit earnings exposure.
(3) Includes a realized net loss, pre-tax of $5 million ($4 million after-tax) for the three months ended December 31, 2024 (2023 – $4 million net loss, pre-tax and $3 million loss, after-tax) and a $12 million net loss, pre-tax ($9 million after-tax) for the year ended December 31, 2024 (2023 – $11 million net loss, pre-tax and $8 million loss after-tax) on FX hedges, as discussed above.
(4) Excludes a MTM loss, after-tax of $25 million for the three months ended December 31, 2024 (2023 – $15 million gain, after-tax) and a MTM loss, after-tax of $31 million for the year ended December 31, 2024 (2023 – $20 million gain, after-tax).
(5) Excludes a gain on sale of LIL, after-tax, of $107 million for the year ended December 31, 2024 (2023 – nil).
(6) Excludes certain charges related to the pending sale of NMGC of $234 million ($217 million after-tax) for the year ended December 31, 2024 (2023 – nil).
(7) Excludes the tax recovery of $58 million related to a specific financing structure and its wind-up and $22 million on reversal of a prior year valuation allowance related to the sale of LIL for the three months and year ended December 31, 2024 (2023 – nil).

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera’s non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company’s ability to generate cash include changes to global macro-economic conditions, downturns in markets served by Emera, impact of fuel commodity price changes on collateral requirements and timely recoveries of fuel and storm costs from customers, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets, and changes in environmental legislation. Emera’s subsidiaries are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment, and that they maintain their credit metrics.

Emera’s future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has an approximate $20 billion capital investment plan over the 2025 through 2029 period and supports ongoing growth. Capital investments at Emera’s regulated utilities are subject to regulatory approval.

Emera currently has a strong liquidity position and ability to service debt obligations as they come due to meet any near-term capital investment requirements as currently planned. Emera plans to use cash from operations, debt raised at the utilities, Corporate equity, and proceeds from the pending sale of NMGC to support normal operations, repayment of existing debt, and capital requirements. Debt raised at certain of the Company’s utilities is subject to applicable regulatory approvals. Generally, Corporate equity requirements in support of the Company’s capital investment plan are expected to be funded through issuance of preferred equity and issuance of common equity through Emera’s DRIP and ATM programs.

Emera has total committed credit facilities with varying maturities that cumulatively provide $2.3 billion CAD and $1.6 billion USD of credit, with approximately $1.1 billion CAD and $593 million USD undrawn and available at December 31, 2024. The Company was holding a cash balance of $204 million, which includes $8 million classified as assets held for sale, related to the pending sale of NMGC, at December 31, 2024. For further discussion, refer to the “Debt Management” section below.

Consolidated Cash Flow Highlights

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2024 and 2023 include:

millions of dollars	2024	2023	$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$ 588**	$ 332	$ 256
Provided by (used in):			
Operating cash flow before changes in working capital	**2,194**	2,336	(142)
Change in working capital	**452**	(95)	547
Operating activities	**$ 2,646**	$ 2,241	$ 405
Investing activities	**(2,218)**	(2,917)	699
Financing activities	**(818)**	939	(1,757)
Effect of exchange rate changes on cash, cash equivalents, restricted cash, and cash associated with assets held for sale	**23**	(7)	30
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, end of period	**$ 221**	$ 588	$ (367)

Cash Flow from Operating Activities

Net cash provided by operating activities increased $405 million to $2,646 million for the year ended December 31, 2024, compared to $2,241 million in 2023.

Cash from operations before changes in working capital decreased $142 million for the year ended December 31, 2024. This decrease was due to increased storm cost recovery regulatory asset related to Hurricane Helene and Hurricane Milton at TEC, lower fuel clause recoveries at TEC, and the reversal of the Nova Scotia Cap-and-Trade Program provision in Q1 2023 at NSPI. These were partially offset by the NSPML Refund, favourable change in regulatory liabilities due to the 2023 gas hedge settlements at NMGC, increased electric revenue at NSPI, proceeds from the FAM asset sale to Invest Nova Scotia at NSPI, and increased earnings and the recovery of the conservation clause expense at PGS.

Changes in working capital increased operating cash flows by $547 million for the year ended December 31, 2024. This increase was due to increased accounts payable at TEC due to Hurricane Helene and Hurricane Milton storm cost accruals, favourable changes in cash collateral positions at NSPI, lower accounts receivable at TEC, reversal of the Nova Scotia Cap-and-Trade Program provision in Q1 2023 at NSPI, favourable changes in fuel inventory at NSPI and TEC, and favourable changes in accounts payable at NSPI, NMGC, and PGS. These were partially offset by unfavourable changes in cash collateral positions at EES, unfavourable changes in accounts receivable at NMGC due to the receipt of the 2023 gas hedge settlement, unfavourable changes in natural gas inventory at EES, and unfavourable changes in accounts receivable at NSPI.

Cash Flow used in Investing Activities

Net cash used in investing activities decreased $699 million to $2,218 million for the year ended December 31, 2024, compared to $2,917 million in 2023. The decrease was primarily due to the proceeds of $927 million received on the sale of Emera’s LIL equity interest, partially offset by higher capital investment in 2024.

Capital expenditures for the year ended December 31, 2024, including AFUDC, were $3,206 million compared to $2,976 million in 2023. Details of 2024 capital spending by segment are shown below:

- $1,998 million – Florida Electric Utility (2023 – $1,771 million);
- $494 million – Canadian Electric Utilities (2023 – $461 million);
- $626 million – Gas Utilities and Infrastructure (2023 – $673 million);
- $81 million – Other Electric Utilities (2023 – $63 million); and
- $7 million – Other (2023 – $8 million).

Cash Flow from Financing Activities

Net cash used in financing activities decreased $1,757 million to $818 million for the year ended December 31, 2024, compared to net cash provided by financing activities of $939 million in 2023. This decrease was due to lower issuance of long-term debt at PGS, NSPI, and NMGC, higher repayment of Emera's committed credit facilities using the LIL transaction proceeds, retirement of long-term debt at Emera, TEC and NMGC, and higher net repayments under committed credit facilities at NSPI. These were partially offset by proceeds from the fixed-to-fixed reset rate junior subordinated notes issuance by EUSHI Finance Inc., lower short-term debt repayments at TEC, and issuance of long-term debt at TEC.

Working Capital

As at December 31, 2024, Emera’s cash and cash equivalents were $196 million (2023 – $567 million) and Emera’s investment in non-cash working capital was $224 million (2023 – $831 million). Of the cash and cash equivalents held at December 31, 2024, $185 million was held by Emera’s foreign subsidiaries (2023 – $482 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

Contractual Obligations

As at December 31, 2024, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2025	2026	2027	2028	2029	Thereafter	Total
Long-term debt principal (1)	$ 234	$ 3,279	$ 120	$ 651	$ 1,764	$ 13,192	$ 19,240
Interest payment obligations (2)(3)	884	799	712	705	636	8,210	11,946
Purchased power (4)	307	277	368	368	369	4,487	6,176
Transportation (5)(6)	742	545	544	454	412	3,228	5,925
Capital projects	604	287	24	-	-	-	915
Fuel, gas supply and storage (7)	591	94	21	5	-	-	711
Pension and post-retirement obligations (8)	31	32	68	72	73	224	500
Asset retirement obligations	9	1	1	2	1	422	436
Other	160	95	80	59	59	264	717
	$ 3,562	$ 5,409	$ 1,938	$ 2,316	$ 3,314	$ 30,027	$ 46,566

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

(1) Includes $696 million related to NMGC (2026: $100 million, and $576 million thereafter).

(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2024, including any expected required payment under associated swap agreements.

(3) Includes $353 million related to NMGC (2025: $26 million, 2026: $26 million, 2027: $23 million, 2028: $23 million, 2029: $23 million, and $232 million thereafter).

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

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

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

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

(8) Includes the estimated contractual obligation, which is calculated as the current legislatively required contributions to the registered funded pension plans, plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.

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

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

Forecasted Consolidated Capital Investments

The 2025 forecasted consolidated capital investments, including AFUDC, are as follows:

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Total
Generation	$ 358	$ 117	$ -	$ 32	$ -	$ 507
New renewable generation	567	-	-	81	-	648
Electric transmission	169	188	-	53	-	410
Electric distribution	614	140	-	-	-	754
Gas transmission and distribution	-	-	481	-	-	481
Facilities, equipment, vehicles, and other	547	40	5	23	5	620
	$ 2,255	$ 485	$ 486	$ 189	$ 5	$ 3,420

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to unsecured committed syndicated revolving and non-revolving bank lines of credit in either CAD or USD per the table below.

millions of dollars in currency as noted below	**Maturity**	**Credit Facilities**	**Utilized**	**Undrawn and Available**
In CAD:				
Emera – committed revolving credit facility	June 2029	$ 1,300	$ 792	$ 508
NSPI – committed revolving credit facility	June 2029	800	189	611
Emera – non-revolving facility	February 2026	200	200	-
In USD:				
TEC – committed revolving credit facility	December 2028	800	637	163
TECO Finance – committed revolving credit facility	December 2028	400	184	216
PGS – revolving facility	December 2028	250	138	112
NMGC – revolving credit facility	December 2026	125	34	91
Other – committed revolving credit facilities	Various	24	13	11

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2024. Emera's significant covenant is listed below:

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

Recent significant financing activity for Emera and its subsidiaries are discussed below by segment:

Florida Electric Utilities

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

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

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

Canadian Electric Utilities

On June 24, 2024, NSPI amended its unsecured non-revolving credit facility to extend the maturity date from July 15, 2024 to June 24, 2025 and reduce the facility from $400 million to $300 million. On December 16, 2024, NSPI repaid the $300 million unsecured non-revolving credit facility using the net proceeds from the NSPML debt issuance transferred to NSPI as approved by the UARB. For more information on the FLG, refer to the “Business Overview and Outlook – Canadian Electric Utilities” section.

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

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

Gas Utilities and Infrastructure

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

On July 30, 2024, NMGI repaid its $150 million USD fixed rate notes upon maturity.

Other Electric Utilities

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

Other

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

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

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

Proceeds from the $500 million USD note issuance discussed above were used to repay an Emera US Finance LP $300 million USD senior note upon maturity in June 2024, and to repay an NMGI $150 million USD fixed rate notes upon maturity in July 2024. The remaining proceeds were used for general corporate purposes.

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

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

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

Credit Ratings

Emera and its subsidiaries have been assigned the following senior unsecured debt ratings:

	Fitch	S&P	Moody's	DBRS
Emera (1)	BBB (Negative)	BBB- (Stable)	Baa3 (Negative)	N/A
TEC (1)	A (Negative)	BBB+ (Stable)	A3 (Negative)	N/A
PGS	A (Negative)	N/A	N/A	N/A
NMGC (2)	BBB+ (Stable)	N/A	N/A	N/A
NSPI (1)	N/A	BBB- (Stable)	N/A	BBB (high)(stable)

(1) On January 22, 2025, Standard and Poor's ("S&P") revised its outlook on Emera and its subsidiaries to stable from negative with no change to existing ratings.
(2) On May 30, 2024, Fitch Ratings ("Fitch") revised NMGC's outlook to stable from negative.

Guaranteed Debt

As of December 31, 2024, the Company had $2.95 billion USD (2023 – $2.75 billion USD) senior unsecured notes and junior subordinated notes (collectively referred to as the "US Notes") outstanding.

The US Notes are fully and unconditionally guaranteed, on a joint and several basis, and in the case of the fixed-to-fixed reset rate junior subordinated notes due 2054 only, on a joint, several and subordinated basis, by Emera and Emera US Holdings Inc. ("EUSHI") (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP. EUSHI Finance is owned indirectly by Emera through EUSHI.

Other subsidiaries of the Company do not guarantee the US Notes (such subsidiaries are referred to as the "Non-Guarantor Subsidiaries"); however, Emera has unrestricted access to the assets of consolidated entities.

In compliance with Rule 13-01 of Regulation S-X, the Company is including summarized financial information for Emera, EUSHI, Emera US Finance LP and EUSHI Finance (together, the "Obligor Group"), on a combined basis after transactions and balances between the combined entities have been eliminated. Investments in and equity earnings of the Non-Guarantor Subsidiaries have been excluded from the summarized financial information.

The Obligor Group was not determined using geographic, service line or other similar criteria and, as a result, the summarized financial information includes portions of Emera's domestic and international operations. Accordingly, this basis of presentation is not intended to present Emera's financial condition or results of operations for any purpose other than to comply with the specific requirements for guarantor reporting.

Summarized Statement of Income (Loss)

The Company recognized income related to guaranteed debt under the following categories:

For the	Year ended December 31			
millions of dollars		**2024**		2023
Loss from operations	**$**	**(279)**	$	(62)
Net gains (1)	**$**	**442**	$	394

(1) Includes $1,352 million (2023 – $962 million) in interest and dividend income, net, from non-guarantor subsidiaries.

Summarized Balance Sheet

The Company has the following categories on the balance sheet related to guaranteed debt:

As at				December 31
millions of dollars		**2024**		2023
Current assets (1)	**$**	**391**	$	272
Goodwill		**5,858**		5,871
Other assets (2)		**6,474**		6,263
Total assets (3)	**$**	**12,723**	$	12,406
Current liabilities (4)	**$**	**611**	$	1,264
Long-term liabilities (5)		**13,129**		11,956
Total liabilities	**$**	**13,740**	$	13,220

(1) Includes $217 million (2023 – $178 million) in amounts due from non-guarantor subsidiaries.
(2) Includes $5,937 million (2023 – $5,906 million) in amounts due from non-guarantor subsidiaries.
(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are $42,951 million (2023 – $39,480 million).
(4) Includes $184 million (2023 – $167 million) due to non-guarantor subsidiaries.
(5) Includes $5,980 million (2023 – $5,854 million) due to non-guarantor subsidiaries.

Outstanding Stock Data

Common Stock

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

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

As at February 14, 2025, the amount of issued and outstanding common shares was 297.7 million.

If all outstanding stock options were converted as at February 14, 2025, an additional 3.8 million common shares would be issued and outstanding.

ATM Equity Program

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

Preferred Stock

As at February 19, 2025, Emera had the following preferred shares issued and outstanding: Series A – 4.9 million; Series B – 1.1 million; Series C – 10.0 million; Series E – 5.0 million; Series F – 8.0 million; Series H – 12.0 million; Series J – 8.0 million, and Series L – 9.0 million. Emera’s preferred shares do not have voting rights unless the Company fails to pay, in aggregate, eight quarterly dividends.

On January 8, 2025, Emera announced that it would not redeem the outstanding Series F preferred shares on February 15, 2025. During the conversion period between January 15, 2025 and January 31, 2025, subject to certain conditions, the holders of Series F shares had the right, at their option, to convert all or any of their Series F shares, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series G on February 15, 2025.

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

On February 6, 2025, Emera announced after having taken into account all conversion notices received from holders none of the Series F preferred shares were converted to Series G preferred shares.

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit (“DB”) pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a multi-year period. Expected cash flow for DB pension plans is $41 million in 2025 (2024 – $36 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera’s DB pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company’s goal of preserving capital with an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per each pension plan’s investment policy and governance framework. The asset allocation includes investments in the assets of domestic and global equities, domestic and global bonds and short-term investments. The Company reviews investment manager performance on a regular basis and adjusts the plans’ asset mixes as needed in accordance with the pension plans’ investment policy.

Emera’s projected contributions to defined contribution pension plans are $56 million for 2025 (2024 – $51 million).

Defined Benefit Pension Plan Summary

in millions of dollars

Plans by region	TECO Holdings	NSPI	Caribbean	Total
Assets as at December 31, 2024	$ 987	$ 1,495	$ 11	$ 2,493
Accounting obligation at December 31, 2024	$ 970	$ 1,380	$ 17	$ 2,367
Accounting expense (income) during fiscal 2024	$ 5	$ (11)	$ 3	$ (3)

Off-Balance Sheet Arrangements

Defeasance

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2024 totalled $200 million (2023 – $200 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

Guarantees and Letters of Credit

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

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

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

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

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

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

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

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

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of one to two per cent per year. On September 18, 2024, the Board approved an increase in the annual common share dividend rate to $2.9000 from $2.8700 per common share. The first quarterly dividend payment at the increased rate was paid on November 15, 2024.

Emera's common share dividends paid in 2024 were $2.8775 ($0.7175 in Q1, Q2, and Q3 and $0.7250 in Q4) per common share and for 2023 were $2.7875 ($0.6900 in Q1, Q2, and Q3 and $0.7175 in Q4) per common share. This represents a dividend payout ratio of net income of 168 per cent in 2024 (2023 – 78 per cent) and a dividend payout ratio of adjusted net income of 98 per cent in 2024 (2023 – 94 per cent).

TRANSACTIONS WITH RELATED PARTIES

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

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

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

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

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

ENTERPRISE RISK AND RISK MANAGEMENT

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

The significant business risks to Emera are described below, many of which are beyond the Company's control, and could have a material adverse effect on Emera or its subsidiaries, or their business operations, liquidity or access to or cost of capital, financial position, prospects, and/or results of operations (herein considered a "Material Adverse Effect"). The nature of risk is such that no such list is comprehensive, and the actual effect of any of the risks discussed could be materially different from what is described below. Additionally, other risks not presently known may arise, risks not currently considered material may become material in the future, or two or more risks which are not themselves material, could together be material.

Regulatory and Political Risk

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

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

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

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

Change in Law Risk

The Company is also exposed to changes in the political environment and leadership, changes in law or regulations, changes to governmental policies, trade disputes, and the imposition of tariffs, any of which may impact the Company's businesses, the markets for energy and inputs thereto, or general economic conditions, and which may result in a Material Adverse Effect. This may include initiatives regarding deregulation or restructuring of the energy industry, which may result in increased competition, and increased or unrecovered costs. State and local policies in some US 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.

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or the resulting operating or compliance costs or other impacts. It may be difficult for Emera to respond in an effective and timely manner to such future legislative, policy or regulatory changes.

Environmental Legislation:
Emera is subject to extensive regulation by federal, provincial, state, regional and local authorities regarding environmental matters, primarily related to its utility operations. This includes laws, regulations and policies relating to GHG emissions, renewable energy standards, climate change, air quality, water quality and usage, waste management, wastewater discharges, soil quality, aquatic and terrestrial habitats, hazardous waste, health, endangered species, and wildlife mortality.

In some jurisdictions where Emera operates, government legislation and policy has included timelines for mandated shutdowns of coal-fired generating facilities, has required a certain percentage of electricity be generated from renewables, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and long terms, these could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix and reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. The Government of Canada has also enacted regulations imposing emissions standards on coal-fired generation that would effectively require the decommissioning of such facilities. While Nova Scotia is exempted from such regulations through 2029, there is no guarantee that such exemption will continue into the future. Failure to meet such goals by 2030 or comply with applicable legislation or regulation could result in a Material Adverse Effect.

Per- and polyfluoroalkyl substances ("PFAS") are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. The Company does not manufacture PFAS but because these emerging contaminants of concern are so ubiquitous in products and the environment, it may impact Emera's operations. Changes in environmental laws and regulations related to PFAS could result in new costs or obligations for investigation and cleanup and change the Company's strategy for land acquisition for projects such as solar generation and could result in a Material Adverse Effect.

These and new or revised environmental laws, regulations, policies, or interpretations of those laws, regulations or policies could result in a Material Adverse Effect by, among other things, preventing or delaying the development of energy infrastructure projects, restricting the use or output of certain facilities, requiring the early retirement of certain generation facilities that could result in stranded costs, limiting the availability or use of certain fuels required for the production of electricity, requiring additional pollution control equipment, curtailing sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses, changing the nature and timing of capital investments, requiring significant capital investments, imposing operating or other costs associated with compliance including carbon taxes or emissions allowances, or by limiting or eliminating certain operations or rendering such operations uneconomical. Impacts could be more significant in the future as the result of new or revised laws or requirements or stricter or more expansive application of existing environmental laws, regulations and policies. Failure to recover environmental costs in a timely manner through rates may also result in a Material Adverse Effect.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, exposing Emera to legal or regulatory proceedings, disputes, civil fines, injunctive relief, criminal penalties and other sanctions, which could result in a Material Adverse Effect.

Weather Risk

A Material Adverse Effect may arise from weather seasonal variations impacting energy consumption, as well as severe weather events, changing air temperatures, wildfires and other severe weather conditions that are expected to become more frequent and intense as a result of climate change. Refer to “Climate Change Risk”.

The temperature, seasonal variations, and other weather conditions significantly influence the availability and demand for electricity and natural gas by customers, the price of energy commodities, such as fuel used by the Company’s utilities, and the production of electricity at power generation facilities. For example, NSPI could see lower sales in winter months if temperatures are warmer than expected.

Severe weather events or conditions such as hurricanes, floods, storm surge, tornadoes, droughts, fires, extreme temperatures, snow or ice storms, and other natural disasters create a risk of physical damage to the Company’s assets and a risk of extended service outages or fuel supply disruptions. For example, high winds can cause widespread damage to transmission and distribution infrastructure, solar generation, and wind-powered generation. Substantially all of the Company’s fossil fueled generation assets are located at or near coastal sites and, as such, are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding.

Severe weather events or conditions could reduce revenues and require the Company to incur additional costs, such as repair and replacement costs, costs of replacement power and fuel, increased insurance costs, and the need to access additional financing sources. These could result in a Material Adverse Effect if not resolved or mitigated in a timely and efficient manner through insurance or regulatory cost recovery. This risk to transmission and distribution facilities is typically not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves, or after the fact through the establishment of regulatory assets. Recovery is not assured, is subject to prudency review, and may be subject to delay resulting in increased debt and debt servicing costs.

Severe weather events or other catastrophic natural disasters could also result in long-term reductions in demand for electricity or natural gas or the slowing of customer growth in one or more of the Company’s service territories, which could have a Material Adverse Effect. The impact of extreme weather events would be amplified if the same events affect multiple utilities in the Company’s portfolio.

High winds and lack of precipitation also increase the risk of wildfires resulting from the Company’s infrastructure or for which the Company may otherwise have responsibility. If it is found to be responsible for such a fire, the Company could suffer material costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. If not recovered through these means or if recovery is delayed, they could result in a Material Adverse Effect. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

The Company purchases power from third-party owned hydroelectricity sources and operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities.

Climate Change Risk

Physical Risk:
Climate change may negatively impact the Company's operations as a result of increased frequency and intensity of weather events and related physical risks, any of which could result in a Material Adverse Effect (for more information refer to "Weather Risk" and "System Operating and Maintenance Risks"). An increase in physical risk associated with climate change can also adversely impact the cost and availability of insurance, insurance deductibles and self-retention, as well as credit ratings, which could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability (refer to "Liquidity and Capital Markets Risk").

Transition Risk:
As government policy and the economy transition toward decarbonization in many jurisdictions, the Company is exposed to risks arising from policy, legal, technology, and market changes, which could result in a Material Adverse Effect. The energy transition will require the Company to address changes to environmental policies, laws and regulations which are being proposed and adopted in many jurisdictions in response to concerns regarding the effects or impacts of climate change (refer to "Environmental Legislation"). The pace of such new initiatives is expected to accelerate in some jurisdictions.

The Company will be required to manage the impacts of these changes on customer demand and rates, while integrating increased amounts of intermittent renewable energy sources and new technologies, implementing and making the investments required to meet new resiliency and security standards, and adapting the Company's infrastructure and generating capacity to meet changing customer demands and usage patterns. The energy transition and the ability of the Company to achieve mandated climate related targets and goals will require significant capital investment, effective engagement with policymakers, regulators and stakeholders, and depend upon many factors which are outside of the Company's direct control. Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets.

Given concerns regarding carbon-emitting generation, assets and businesses may, over time, become difficult or uneconomic to insure in commercial insurance markets. Some insurance companies have begun to limit their exposure to coal-fired electricity generation and are evaluating the medium and long-term impacts of climate change which may result in less insurance capacity, more restrictive coverage and increased premiums. The Company could also face litigation or regulatory action related to environmental harms from GHG emissions or failure to substantiate certain environmental claims.

The failure to effectively respond to climate change transition risks could adversely affect the Company's ability to deliver safe, reliable, and cost-effective service, the Company's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital, each of which could result in a Material Adverse Effect.

Cybersecurity Risk

Emera is exposed to potential risks related to cyberattacks, data breaches, cyber-extortion, and unauthorized access that could result in a Material Adverse Effect. The Company relies on IT systems, cloud infrastructure, third-party service providers and the diligence of its team members to effectively manage and safely operate its assets. This includes controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other enterprise systems. As the Company operates critical energy infrastructure, it may be at greater risk of cyberattacks, which could include those from nation-state cyber threat actors. Major emerging and ongoing global conflicts may also elevate this risk, by increasing the sophistication, magnitude, and frequency of cyberattacks.

Cyberattacks can reach the Company's assets and information via their interfaces with third parties or the public internet and gain access to critical and non-critical infrastructures. Cyberattacks can also occur via personnel with access to critical assets or trusted networks. Methods used to attack critical assets could include generic or energy-sector-specific malware delivered via network transfer, removable media, attachments, links in e-mails or other communications, or social engineering. The methods used by attackers are continuously evolving and can be difficult to predict and detect and may become more sophisticated, frequent, severe, and difficult to stop to the extent that attackers are able to leverage evolving artificial intelligence models or tools.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt energy supply and delivery, business operations, or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers, unavailability of critical assets, safety issues, compromise billing and customer-facing information, such as outage maps, disrupt internal control and financial processes, or result in the release, loss, corruption, destruction, and/or misuse of critical, sensitive, confidential or proprietary information, intellectual property, or personal information of customers or employees. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Cyberattacks or unauthorized access may cause lost revenues, costs, losses, regulatory penalties and third-party damages all, or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. This could result in a Material Adverse Effect and there is no assurance that cyberattacks or other security breaches can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards and policies derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework, periodic security testing, program maturity objectives, cybersecurity incident readiness program, and employee communication and training. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and IT including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the United States Department of Homeland Security. The status of key elements of the Company's cybersecurity program is reported to the RSC. The Board oversees risk and mitigation plans in relation to cybersecurity risks and receives a quarterly update in a risk dashboard at each regularly scheduled Board meeting.

Energy Consumption Risk

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, weather events, customers' focus on energy efficiency, changes in rates, and advancements in new technologies such as rooftop solar, electric vehicles, data centers, and battery storage. Government policies promoting energy efficiency, distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings, and cash flows and result in a Material Adverse Effect.

Foreign Exchange Risk

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

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

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

Liquidity and Capital Markets Risk

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

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

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

General Economic Risk

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

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

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

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

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

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

Public Health Crisis Risk

An outbreak of infectious disease, a pandemic or other public health threats, or a fear of any of the foregoing, could result in a Material Adverse Effect to Emera and its subsidiaries. This could include causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital investments, capital market activities, and counterparty risk; which could result in a Material Adverse Effect.

Health and Safety

The Company's operations inherently involve risk to the health and safety of employees, contractors and members of the public. Personal injury or loss of life resulting from failure to implement or observe appropriate health and safety procedures or comply with health and safety laws and regulations could result in adverse operational, reputational, legal, regulatory, or financial impacts, any of which could have a Material Adverse Effect.

Project Development and Land Use Rights Risk

The Company's capital plan includes significant investment in generation, infrastructure modernization, and customer-focused technologies. Any projects planned or currently in construction, particularly significant capital projects, may be subject to risks that could result in a Material Adverse Effect including, but not limited to, impact on costs from schedule delays, increased demand for renewable energy inputs, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial, state, regional and local levels. There is no assurance that Emera will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

Some of the Company’s assets are located on land owned by third parties, including Indigenous Peoples, and may be subject to land claims. Present or future assets may be located on lands that have been used for traditional purposes and therefore subject to specific consultations, consents, or conditions for development or operation. If the Company’s rights to locate and operate its assets on any such lands are subject to expiry or become invalid, it may incur material costs to renew rights or obtain such rights. If reasonable terms for land-use rights cannot be negotiated, the Company may incur significant costs to remove and relocate its assets and restore the land. Additional costs incurred could cause projects to be uneconomical to proceed with.

Counterparty Risk

Emera is exposed to risk related to its reliance on certain key partners, suppliers, and customers, any of which may endure financial challenges resulting from commodity price and market volatility, economic instability or adversity, adverse political or regulatory changes and other causes which may cause or contribute to such parties’ insolvency, bankruptcy, restructuring or default on their contractual obligations to Emera. Emera is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty’s non-performance under an agreement.

There is no assurance that management strategies will be effective, and significant counterparty defaults could result in a Material Adverse Effect.

Supply Chain Risk

Emera’s ability to meet customer energy requirements, respond to storm-related disruptions and execute on the capital investment program in a cost-effective and timely manner are dependent on maintaining an efficient supply chain. Domestic and global supply chain issues may delay the delivery, increase the cost, or result in shortages of certain materials, fuel, equipment and other resources that are critical to the Company’s operations. These disruptions may be further exacerbated by inflationary pressures, labour shortages, more frequent and severe weather events, government incentives increasing demand for clean energy projects, changes in carbon-related costs, policies and regulations, and the impact of international conflicts. In addition, global supply chains and the financial condition and results of the business could be Materially Adversely Affected by the imposition of custom duties or other tariffs, or an increase in trade restrictions in the future. Failure to eliminate or manage supply chain constraints may impact the availability and cost of items and labour that are necessary to support operations and capital investment and could have a Material Adverse Effect.

Fuel Supply Disruptions:
Emera’s electric and natural gas utilities are also exposed to the risk of fuel supply chain disruptions, both within and outside their service territories, which may be caused by severe weather or natural disasters. This may also be caused by damage to, operational issues with, terrorist or cyberattacks on, third party fuel production, storage, pipeline, and distribution facilities. Significant unanticipated fuel supply disruptions could result in increased exposure to commodity price risk for Emera’s regulated electric and gas utilities and Emera Energy, and these could have a Material Adverse Effect.

Commodity Price Risk

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

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

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

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

Future Employee Benefit Plan Performance and Funding Risk

Emera subsidiaries have both defined benefit and defined contribution employee pension plans that cover employees and retirees. All defined benefit plans are closed to new entrants, except for the TECO Holdings Group Retirement Plan and the Grand Bahama Power Company Limited Union Employees' Pension Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, inflation, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. The three largest drivers of cost are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates and future inflation and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could have a Material Adverse Effect.

Labour Risk

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could have a Material Adverse Effect.

Approximately 30 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have a Material Adverse Effect.

IT Risk

Emera relies on various IT systems to manage operations, including increasing reliance on IT solutions operated by third parties, such as software as a service and third-party cloud hosting. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its IT, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems. Emera's digital transformation strategy, including investment in infrastructure modernization and customer focused technologies, is driving increased investment in IT solutions, resulting in increased project risks associated with the implementation of these solutions.

Income Tax Risk

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

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, supply chain issues impacting timely access to critical equipment, activities of third parties, terrorism, cyberattacks, human error, damage to facilities, and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can also be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties, terrorism, cyberattacks, and damage to the pipeline facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect customer and public confidence, and public safety and have a Material Adverse Effect.

Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all these losses, which could have a Material Adverse Effect.

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. A significant portion of Emera's electric utilities' transmission and distribution assets and its gas utilities' distribution assets are not insured, as is customary in the industry, as the cost of coverage is prohibitive. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred will be covered by insurance.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits, or claims that fall within a significant self-insured retention could have a Material Adverse Effect, if regulatory recovery is not available.

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

The Company manages 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 value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

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

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

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars		December 31 2024		December 31 2023
Regulatory Deferral:				
Derivative instrument assets (1)	**$**	**45**	$	16
Derivative instrument liabilities (2)		**(40)**		(76)
Regulatory assets (1)		**53**		88
Regulatory liabilities (2)		**(44)**		(17)
Net asset	**$**	**14**	$	11
HFT Derivatives:				
Derivative instrument assets (1)	**$**	**122**	$	202
Derivatives instruments liabilities (2)		**(542)**		(421)
Net liability	**$**	**(420)**	$	(219)
Other Derivatives:				
Derivative instrument assets (1)	**$**	**-**	$	22
Derivatives instruments liabilities (2)		**(36)**		(7)
Net asset (liability)	**$**	**(36)**	$	15

(1) Current, other and assets held for sale.
(2) Current, long-term and liabilities associated with assets held for sale.

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars		Year ended December 31 2024		2023
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$**	**(44)**	$	62
HFT Derivatives:				
Non-regulated operating revenues	**$**	**207**	$	1,037
Other Derivatives:				
OM&G	**$**	**14**	$	(9)
Other income, net		**(56)**		17
Net gains (losses)	**$**	**(42)**	$	8
Total net gains	**$**	**121**	$	1,107

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

As of December 31, 2024, the unrealized gain in AOCI was $12 million, after-tax (December 31, 2023 – $14 million, after-tax). For the year ended December 31, 2024, unrealized gains of $2 million (2023 – $2 million) have been reclassified from AOCI into interest expense.

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). The Company's internal control framework is based on criteria published in the Internal Control Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company's DC&P and ICFR as at December 31, 2024 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

There were no changes in the Company's ICFR, during the year ended December 31, 2024, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING 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.

Rate Regulation

The rate-regulated accounting policies of Emera's rate-regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from the accounting policies of non-rate-regulated companies. Differences occur when regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on expectations of the future actions of the regulators. Assumptions and judgments used by regulatory authorities continue to have an impact on recovery of costs, rates earned on invested capital, and the timing and amount of assets to be recovered. Application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

As at December 31, 2024, the Company had recorded $3,427 million (2023 – $3,105 million) of regulatory assets and $1,880 million (2023 – $1,772 million) of regulatory liabilities.

Accumulated Reserve – Cost of Removal

TEC, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E upon retirement that are not legally required. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. Costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. As at December 31, 2024, the balance of the Accumulated reserve – COR within regulatory liabilities was $733 million (2023 – $849 million).

Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future expectations.

The accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics - including age, compensation levels, employment periods, contribution levels and earnings - could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. Changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs, could change annual funding requirements. This could have a significant impact on the Company's annual earnings and cash requirements.

Pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in changes to pension costs in future periods.

The Company's accounting policy is to amortize the net actuarial gain or loss that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period. For the largest plans this is currently 8.2 years (8.4 years for 2024 benefit cost) for Canadian plans and a weighted average of 11.6 years for US plans. The Company's use of smoothed asset values reduces volatility related to amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

	2024		2023	
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Holdings Group Retirement Plan	**5.27%**	**7.05%**	5.55%	7.05%
TECO Holdings Group Supplemental Executive Retirement Plan (1)	**5.15%**	**N/A**	5.45%/5.31%	N/A
TECO Holdings Group Benefit Restoration Plan (1)	**5.18%**	**N/A**	5.48/5.30/5.49%	N/A
TECO Holdings Post-retirement Health and Welfare Plan	**5.28%**	**N/A**	5.53%/6.14%	N/A
NMGC Retiree Medical Plan	**5.28%**	**4.25%**	5.55%	2.50%
NSPI	**4.63%, 4.62%**	**6.00%**	5.17%, 5.19%	6.25%
GBPC Salaried	**5.75%**	**6.00%**	5.75%	6.00%
GBPC Union	**5.75%**	**5.35%**	5.75%	5.35%

(1) The discount rate for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $56 million in 2024 (2023 – $43 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2024 benefit cost of $0.5 million and $3.0 million, respectively (2023 – $0.5 million and $2.5 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of estimates included in determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2024, unbilled revenues totalled $342 million (2023 – $363 million) on total regulated operating revenues of $7,447 million (2023 – $7,235 million).

PP&E

PP&E represents 61 per cent of total assets on the Company's balance sheet and includes generation, transmission and distribution, and other assets of the Company.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of depreciable assets in each category. The service lives of regulated PP&E are determined based on depreciation studies and require appropriate regulatory approval. Due to the magnitude of the Company's PP&E, changes in estimated depreciation rates can have a material impact on depreciation expense and accumulated depreciation.

Depreciation expense was $1,135 million for the year ended December 31, 2024 (2023 – $1,019 million).

Goodwill Impairment Assessments

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 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. Application of the goodwill impairment test requires management judgment on significant assumptions and estimates. 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. Significant assumptions used in estimating the FV of a reporting unit include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting units' net operating loss ("NOL"), and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

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

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

As of December 31, 2024, the Company had goodwill with a total carrying amount of $5,858 million (December 31, 2023 – $5,871 million). The change in the carrying value of goodwill from 2023 to 2024 was primarily a result of the impairment of the goodwill assigned to the NMGC reporting unit and NMGC goodwill included in disposal units classified as held for sale, partially offset by the effect of the FX translation of Emera's foreign affiliates.

Long-Lived Assets Impairment Assessments

The Company 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 the 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 believes accounting estimates related to asset impairments are critical estimates, as they are highly susceptible to change and the impact of an impairment on reported assets and earnings could be material. Management is required to make assumptions based on expectations regarding results of operations for significant/indefinite future periods and current and expected market conditions in such periods. Markets can experience significant uncertainties. Estimates based on 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. Assumptions made by management are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

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

Income Taxes

Income taxes are determined based on expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that deferred income tax assets will be recovered from future taxable income is assessed, and assumptions are made about expected timing of reversal of deferred income tax assets and liabilities. Uncertainty associated with application of tax statutes and regulations and outcomes of tax audits and appeals, requires that judgments and estimates be made in the accrual process and in calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" threshold may be recognized or continue to be recognized. Unrecognized tax benefits are evaluated quarterly and changes are recorded based on new information, including issuance of relevant guidance by the courts or tax authorities and developments occurring in examinations of the Company's tax returns.

The Company believes accounting estimates related to income taxes are critical estimates. Realization of deferred income tax assets depends on the generation of sufficient taxable income, both operating and capital, in future periods. A change in estimated valuation allowance could have a material impact on reported assets and results of operations. Administrative actions of tax authorities, changes in tax law or regulation, and uncertainty associated with the application of tax statutes and regulations, could change the Company's estimate of income taxes, including the potential for elimination or reduction of the Company's ability to realize tax benefits and to utilize deferred income tax assets.

Asset Retirement Obligations

Measurement of the FV of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with legally obligated costs. There are uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations, and advances in remediation technologies. Emera has AROs associated with remediation of generation, transmission, distribution and pipeline assets.

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. Accretion expense is included as part of "Depreciation and amortization expense". Any accretion expense not yet approved by the regulator is recorded in "PP&E" and included in the next depreciation study. Accordingly, changes to the ARO or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

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 when an amount can be determined.

As at December 31, 2024, AROs recorded on the balance sheet were $217 million (2023 – $192 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $453 million (2023 – $426 million), which will be incurred between 2025 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Financial Instruments

The Company is required to determine the FV of all derivatives except those that qualify for the NPNS exception. FV is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. FV measurements are required to reflect assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

Level Determinations and Classifications

The Company uses Level 1, 2, and 3 classifications in the FV hierarchy. The FV measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the FV. FV is determined, directly or indirectly, using inputs that are observable for the asset or liability. Only in limited circumstances does the Company enter into commodity transactions involving non-standard features where market observable data is not available or have contract terms that extend beyond five years.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

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

Improvements to Reportable Segment Disclosures

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

Future Accounting Pronouncements

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

Disaggregation of Income Statement Expenses

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

Improvements to Income Tax Disclosures

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

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2024**	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023
Operating revenues	**$ 1,763**	$ 1,802	$ 1,617	$ 2,018	$ 1,972	$ 1,740	$ 1,418	$ 2,433
Net income attributable to common shareholders	**$ 154**	$ 4	$ 129	$ 207	$ 289	$ 101	$ 28	$ 560
EPS – basic	**$ 0.52**	$ 0.01	$ 0.45	$ 0.73	$ 1.04	$ 0.37	$ 0.10	$ 2.07
EPS – diluted	**$ 0.52**	$ 0.01	$ 0.45	$ 0.73	$ 1.04	$ 0.37	$ 0.10	$ 2.07

Quarterly operating revenues and adjusted net income are affected by seasonality. The first quarter provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. Seasonal and other weather patterns, as well as the number and severity of storms, can affect demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the "Significant Items Affecting Earnings" section. Quarter-over-quarter variances are discussed further below.

Q4 2024 compared to Q4 2023
For explanation of variances, refer to the "Consolidated Income Statement Highlights" section.

Q3 2024 compared to Q3 2023
Q3 2024 net income attributable to common shareholders decreased by $97 million and EPS – basic and diluted decreased by $0.36 compared to Q3 2023. The decreases were primarily due to charges related to the pending sale of NMGC; decreased earnings at Emera Energy; lower equity earnings from LIL; lower Corporate income tax recovery due to decreased losses before provision for income taxes; increased Corporate interest expense due to increased interest rates and increased total debt; and increased Corporate preferred share dividends. These changes were partially offset by decreased MTM losses; increased earnings at TEC, PGS, NSPI and NMGC; and lower Corporate OM&G due to the timing difference in the valuation of long-term incentive expense and related hedges. The change in EPS was also impacted by an increase in weighted average shares outstanding.

Q2 2024 compared to Q2 2023
Q2 2024 net income attributable to common shareholders increased by $101 million and EPS – basic and diluted increased by $0.35 compared to Q2 2023. The increases were primarily due to the gain on sale of LIL, after transaction costs; increased earnings at PGS and TEC; increased Corporate income tax recovery due to increased losses before provision for income taxes; and decreased MTM losses. These changes were partially offset by decreased earnings at NMGC and NSPI; higher Corporate interest expense due to increased interest rates and increased total average debt; and FX losses on the translation of USD short-term debt balances in Corporate. The change in EPS was also impacted by an increase in weighted average shares outstanding.

Q1 2024 compared to Q1 2023
Q1 2024 net income attributable to common shareholders decreased by $353 million and EPS – basic and diluted decreased by $1.34 compared to Q1 2023. The decreases were primarily due to increased MTM losses; lower earnings at TEC, NMGC, NSPI and EES; increased Corporate OM&G due to the timing difference in the valuation of long-term incentive expense and related hedges; and increased Corporate interest expense due to increased total debt. These changes were partially offset by higher earnings at PGS and NSPML; and higher income tax recovery at Corporate. The change in EPS was also impacted by an increase in weighted average shares outstanding.