Management's Discussion & Analysis

As at May 13, 2024

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 first quarter of 2024 relative to the same quarter in 2023; and its financial position as at March 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 unaudited condensed consolidated interim financial statements and supporting notes as at and for the three months ended March 31, 2024; and the Emera annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2023. 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 March 31, 2024, Emera's rate-regulated subsidiaries and investments include:

Emera 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
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities
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.

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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, carbon dioxide emissions reduction goals, 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.

The 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; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; future dividend 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; global climate change; 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

Based in Halifax, Nova Scotia, Emera owns and operates cost-of-service rate-regulated electric and gas utilities in Canada, the United States ("US") and the Caribbean. Cost-of-service utilities provide essential electric and gas services in designated territories under franchises and are overseen by regulatory authorities. Emera's strategic focus continues to be safely delivering cleaner, affordable and reliable energy to its customers.

The majority of Emera's investments in rate-regulated businesses are located in Florida with other investments in Nova Scotia, New Mexico and the Caribbean. Emera's portfolio of regulated utilities intends to provide reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), and the amount of equity in the capital structure and the return on that equity ("ROE") as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera's capital investment plan is approximately $9 billion over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. The capital investment plan and additional potential capital result in an anticipated compound annual rate base growth in the range of approximately 7 per cent to 8 per cent through 2026. The capital investment plan includes significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, infrastructure expansion to meet the needs of new and existing customers, and technologies to better support the business and customer experiences. It is anticipated that approximately 75 per cent of Emera's $9 billion capital investment plan over the 2024 through 2026 period will be made in Florida.

Emera's capital investment plan is being funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity, and select asset sales. Generally, equity requirements in support of the Company's capital investment plan 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 at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a priority of the Company.

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. For further information on the non-GAAP measure "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section.

Seasonal patterns and other weather events affect demand and operating costs. Similarly, mark-to-market ("MTM") adjustments and foreign currency exchange can have a material impact on financial results for a specific period. Emera's consolidated net income and cash flows are impacted by movements in the USD relative to the CAD. Emera may hedge both transactional and translational exposure. These impacts, as well as the timing of capital investments and other factors, mean results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

Energy markets worldwide are experiencing significant change and Emera is well-positioned to continue to respond to shifting customer demands and meet the challenges of digitization, decarbonization and decentralized generation, within complex regulatory environments.

Customers depend on energy and are looking for more choice, better control, and greater reliability. The costs of decentralized generation and storage have become more competitive and advancing technologies are transforming how utilities operate and interact with customers. Concurrently, climate change and the increased frequency of extreme weather events are shaping government energy policy. This is also creating a need to replace aging infrastructure and make investments to protect and harden energy systems to deliver energy reliability and system resiliency. These factors combined with inflation, higher interest rates and higher cost of capital increase energy costs, and thus customer rates, at a time when affordability is a challenge.

Emera's strategy is centred on delivering value for customers, and in doing so creating value for shareholders. This includes:

- investing in cleaner and renewable sources of energy, in the related transmission assets, and in energy storage needed to support intermittent renewables;
- supporting increasing demand from customers and the ongoing electrification of other sectors;
- improving system reliability and resiliency, including replacing aging infrastructure and expanding systems to service new customers; and
- investing in new internal and customer-facing technologies for improved cost efficiency and better customer experiences.

Building on its decarbonization progress, Emera is continuing its efforts towards clear carbon reduction goals and a vision to achieve net-zero carbon dioxide emissions by 2050.

This vision is inspired by Emera's strong track record, the Company's experienced team, and a visible path to Emera's interim carbon goals. With existing technologies and resources, and subject to supportive government and regulatory decisions, Emera is working to achieve the following goals compared to corresponding 2005 levels:

- A 55 per cent reduction in carbon dioxide emissions by 2025.
- The retirement of Emera's last existing coal unit no later than 2040.
- An 80 per cent reduction in carbon dioxide emissions by 2040.

Achieving the above climate goals on these timelines is subject to the Company's regulatory obligations and other external factors beyond Emera's control.

Emera seeks to deliver on its Climate Commitment while maintaining its focus on investing in reliability and staying focused on the cost impacts for customers. Emera is also committed to identifying emerging technologies and continuing to work constructively with policymakers, regulators, partners, investors and customers to achieve these goals and realize its net-zero vision.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships.

NON-GAAP FINANCIAL MEASURES AND RATIOS

Emera uses financial measures and ratios that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and ratios are calculated by adjusting certain GAAP measures for specific items. Management believes excluding these items better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business. These measures and ratios are discussed and reconciled below.

Adjusted Net Income Attributable to Common Shareholders, Adjusted Earnings (Loss) Per Common Share ("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 the effect of MTM adjustments as 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. Management 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.

Emera calculates adjusted net income for the Other Electric Utilities and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Refer to "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

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, see the "Dividend Payout Ratio" section in Emera's 2023 annual MD&A.

The following reconciles net income attributable to common shareholders to adjusted net income:

For the	Three months ended March 31			
millions of dollars (except per share amounts)		**2024**		2023
Net income attributable to common shareholders	**$**	**207**	$	560
MTM (loss) gain, after-tax (1)		**(9)**		292
Adjusted net income	**$**	**216**	$	268
EPS – basic	**$**	**0.73**	$	2.07
Adjusted EPS – basic	**$**	**0.76**	$	0.99

(1) Net of income tax recovery of $4 million for the three months ended March 31, 2024 (2023 – $119 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.

Similar to adjusted net income calculations described above, adjusted EBITDA represents EBITDA absent the income effect of MTM adjustments.

The following is a reconciliation of net income to EBITDA and Adjusted EBITDA:

For the millions of dollars	Three months ended March 31 **2024**	 2023
Net income (1)	**$ 225**	$ 576
Interest expense, net	**246**	226
Income tax expense	**28**	162
Depreciation and amortization	**283**	256
EBITDA	**$ 782**	$ 1,220
MTM (loss) gain, excluding income tax	**(13)**	411
Adjusted EBITDA	**$ 795**	$ 809

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Earnings Impact of MTM Loss, After-Tax

The Q1 2023 MTM gain, after-tax, of $292 million decreased $301 million to a MTM loss, after-tax of $9 million in Q1 2024 due to changes in existing positions at Emera Energy Services ("EES"), partially offset by lower amortization of gas transportation assets at EES.

Consolidated Financial Highlights

For the millions of dollars	Three months ended March 31 **2024**	 2023
Adjusted Net Income		
Florida Electric Utility	**$ 85**	$ 107
Canadian Electric Utilities	**87**	92
Gas Utilities and Infrastructure	**98**	94
Other Electric Utilities	**9**	4
Other	**(63)**	(29)
Adjusted net income	**$ 216**	$ 268
MTM (loss) gain, after-tax	**(9)**	292
Net income attributable to common shareholders	**$ 207**	$ 560

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

For the millions of dollars	Three months ended March 31
Adjusted net income – 2023	**$ 268**
Operating Unit Performance	
Decreased earnings at TEC due to unfavourable weather, increased operating, maintenance and general expenses ("OM&G") and higher depreciation, partially offset by customer growth and new base rates	(22)
Decreased earnings at NMGC due lower asset optimization revenues and higher OM&G	(14)
Decreased earnings at NSPI due to increased OM&G, partially offset by higher revenues due to new rates and increased residential sales volume	(11)
Decreased earnings at EES due to less favourable market conditions	(10)
Increased earnings at PGS due to new base rates, partially offset by higher interest expense, OM&G and depreciation expense	21
Increased income from equity investments at NSPML primarily due to the Maritime Link holdback recognized in Q1 2023	5
Corporate	
Increased OM&G, pre-tax, primarily due to timing of long-term compensation hedges	(19)
Increased interest expense, pre-tax, due to increased total debt	(9)
Increased income tax recovery due to increased losses before provision for income taxes	7
Adjusted net income – 2024	**$ 216**

For further details of reportable segment contributions, refer to the "Financial Highlights" section.

For the millions of dollars	Three months ended March 31 **2024**	2023
Operating cash flow before changes in working capital	**$ 631**	$ 654
Change in working capital	**(62)**	(201)
Operating cash flow	**$ 569**	$ 453
Investing cash flow	**$ (604)**	$ (640)
Financing cash flow	**$ (288)**	$ 153

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

As at millions of dollars	**March 31 2024**	December 31 2023
Total assets	**$ 40,031**	$ 39,480
Total long-term debt (including current portion)	**$ 18,491**	$ 18,365

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended March 31 **2024**	2023	Variance
Operating revenues	**$ 2,018**	$ 2,433	$ (415)
Operating expenses	**1,581**	1,539	(42)
Income from operations	**$ 437**	$ 894	$ (457)
Interest expense, net	**$ 246**	$ 226	$ (20)
Income tax expense	**$ 28**	$ 162	$ 134
Net income attributable to common shareholders	**$ 207**	$ 560	$ (353)
Adjusted net income	**$ 216**	$ 268	$ (52)
Weighted average shares of common stock outstanding (in millions)	**285.1**	270.7	14.4
EPS – basic	**$ 0.73**	$ 2.07	$ (1.34)
EPS – diluted	**$ 0.73**	$ 2.07	$ (1.34)
Adjusted EPS – basic	**$ 0.76**	$ 0.99	$ (0.23)
Dividends per common share declared	**$ 0.7175**	$ 0.6900	$ 0.0275
Adjusted EBITDA	**$ 795**	$ 809	$ (14)

Operating Revenues

For Q1 2024, operating revenues decreased $415 million compared to Q1 2023 and, excluding increased MTM loss of $410 million, decreased $5 million. The decrease was due to lower fuel and asset optimization revenues at NMGC; decreased marketing and trading margin at EES; and unfavourable weather at TEC. These decreases were partially offset by new base rates at NSPI, PGS and TEC; and customer growth at TEC and NSPI.

Operating Expenses

For Q1 2024, operating expenses increased $42 million compared to Q1 2023. This increase was due to higher OM&G due to the timing of long-term compensation hedges at Corporate, higher transmission and distribution costs at TEC and NSPI, higher labour costs at PGS and NMGC, storm restoration costs recognized at TEC; higher fuel expense at NSPI and higher depreciation at TEC and PGS. These increases were partially offset by lower cost of natural gas at NMGC; and the Nova Scotia Renewable Electric Regulations ("RER") penalty recognized at NSPI in Q1 2023.

Interest Expense, Net

For Q1 2024, interest expense, net increased $20 million compared to Q1 2023 due to higher interest rates at PGS and increased borrowings to support ongoing operations at Corporate and PGS.

Income Tax Expense

For Q1 2024, income tax expense decreased $134 million compared to Q1 2023 due to decreased income before provision for income taxes.

Net Income and Adjusted Net Income

For Q1 2024, the increase in net income attributable to common shareholders, compared to Q1 2023, was unfavourably impacted by the $301 million increase in MTM loss, after-tax. Excluding this change, adjusted net income decreased $52 million, primarily due to lower earnings at TEC, NMGC, NSPI, and EES; increased Corporate OM&G due to the timing of long-term compensation hedges; and increased Corporate interest expense due to increased total debt. These were partially offset by higher earnings at PGS and NSPML; and higher income tax recovery at Corporate.

Earnings and Adjusted EPS – Basic

Earnings and Adjusted EPS – basic were lower for Q1 2024 compared to Q1 2023 due to decreased earnings, as discussed above, and an increase in weighted average shares outstanding.

Effect of Foreign Currency Translation

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. For additional details on the effects of foreign currency translation, refer to the Company's 2023 annual MD&A.

The relevant CAD/USD exchange rates for 2024 and 2023 are as follows:

	Three months ended March 31		Year ended December 31
	2024	2023	2023
Weighted average CAD/USD	**$ 1.35**	$ 1.34	$ 1.35
Period end CAD/USD exchange rate	**$ 1.36**	$ 1.35	$ 1.32

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

For the millions of USD		Three months ended March 31 **2024**		2023
Florida Electric Utility	**$**	**63**	$	79
Gas Utilities and Infrastructure (1)		**69**		65
Other Electric Utilities		**7**		3
Other segment (2)		**-**		7
Total (3)	**$**	**139**	$	154

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp, and interest expense on Emera Inc.'s USD denominated debt.
(3) Excludes $1 million USD in MTM loss, after-tax, for the three months ended March 31, 2024 (2023 – $232 million USD MTM gain, after-tax).

The translation impact of the change in FX rates on foreign denominated earnings was minimal in Q1 2024 compared to the same period in 2023. The Corporate FX hedges used to mitigate translation risk of USD earnings included in the Other segment decreased net income by $2 million and decreased adjusted net income by $1 million in Q1 2024 compared to the same period in 2023.

BUSINESS OVERVIEW AND OUTLOOK

There have been no material changes in Emera's business overview and outlook from the Company's 2023 annual MD&A, except for the updates as disclosed below. Emera's results have been impacted by macroeconomic conditions, specifically higher interest rates as well as other impacts of inflation. These conditions are likely to continue for the near term. For information on general economic risk, including interest rate and inflation risk, refer to the "Enterprise Risk and Risk Management – General Economic Risk" in Emera's 2023 annual MD&A. For details on Emera's reportable segments, refer to note 1 of the Q1 2024 unaudited condensed consolidated interim financial statements.

Florida Electric Utility

TEC anticipates earning towards the lower end of the ROE range in 2024 but expects earnings to be higher than 2023. Normalizing 2023 for weather, TEC sales volumes in 2024 are projected to be higher than 2023 due to customer growth. TEC expects customer growth rates in 2024 to be comparable to 2023, reflective of the expected economic growth in Florida.

On April 24, 2024, the US Environmental Protection Agency issued its final rules for electric generating units. The rules include new greenhouse gas standards, which apply only to existing coal-fired and new natural gas electric generating units and will therefore have limited impact on TEC. They also include new coal combustion residual ("CCR") rules. TEC is currently evaluating the impact of the new CCR rule at the Big Bend Power Station. TEC expects that prudently incurred costs to comply with new environmental regulations would be eligible for recovery from customers through either the Environmental Cost Recovery Clause or base rates.

On April 2, 2024, TEC requested a base rate increase, reflecting an increased revenue requirement of $297 million USD, effective January 1, 2025, and additional adjustments of $100 million USD and $72 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and other resiliency and reliability projects. A decision by the FPSC is expected by the end of 2024.

On April 2, 2024, TEC requested a mid-course adjustment to its fuel and capacity charges, reflecting a $137 million USD reduction over 12 months, from June 2024 through May 2025. The requested reduction is 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 voted to approve the mid-course adjustment.

In 2024, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2023 – $1.3 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization, storm hardening investments and building resilience.

Canadian Electric Utilities

NSPI

NSPI expects earnings in 2024 to be consistent with 2023 and anticipates earning below its allowed ROE range in 2024. Sales volumes are expected to be higher in 2024 than 2023.

On April 30, 2024, NSPI applied to the UARB for recovery of $22 million of major storm restoration costs deferred to NSPI's UARB approved storm rider in 2023. If approved, recovery of the 2023 costs deferred in the storm rider would begin January 1, 2025 over the 12 months of 2025. A decision from the UARB is expected by the end of 2024.

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 will result in a corresponding decrease of the FAM regulatory asset when recorded in Q2 2024. NSPI will collect the amortization and financing costs related to the $117 million from customers on behalf of Invest Nova Scotia over a 10-year period beginning in Q2 2024, and remit those amounts to Invest Nova Scotia as collected.

In 2024, capital investment, including AFUDC, is expected to be $480 million (2023 – $451 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 of Nova Scotia (the "Province"). For further discussion on environmental legislation and regulations and associated risks, refer to the "Business Overview and Outlook – Canadian Electric Utilities" and "Enterprise Risk and Risk Management" sections respectively of Emera's 2023 annual MD&A. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Nova Scotia Energy Reform Act:
On April 5, 2024, the Province enacted Bill 404 - Energy Reform (2024) Act. This legislation implements certain recommendations made by the Clean Electricity Solutions Task Force, which was established by the Province to advise the provincial government on Nova Scotia's transition away from coal to more renewable sources of energy. 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 working with 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 2024, however additional process steps related to the disclosure of evidence are expected to impact the timeline of the proceeding. NSPI is awaiting further communication from the UARB on the updated timeline and the delays could impact the UARB's ability to issue a decision on the matter in 2024.

NSPML

Equity earnings from NSPML in 2024 are expected to be consistent with 2023.

On December 21, 2023, NSPML received approval to collect up to $164 million in 2024 from NSPI for the recovery of costs associated with the Maritime Link subject to a holdback of $4 million per month. There was no holdback recorded in Q1 2024. NSPML expects to file an application to terminate the holdback mechanism in 2024.

NSPML does not anticipate any significant capital investment in 2024.

LIL

Equity earnings from the LIL are expected to be higher in 2024, compared to 2023, resulting from an increased investment in LIL planned for 2024.

Equity earnings from the LIL investment are based on the book value of the equity investment and the approved ROE of 8.5 per cent. Emera's current equity investment is $750 million, comprised of $410 million in equity contribution and $340 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be $650 million once the final costing has been confirmed by Nalcor Energy ("Nalcor") to determine the amount of the remaining investment.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure USD earnings are anticipated to be higher in 2024 than 2023, primarily due to a base rate increase effective January 2024 at PGS and an expected base rate increase effective October 2024 at NMGC, partially offset by increased operating expenses and lower asset optimization revenues expected at NMGC.

PGS expects rate base to be higher than in 2023 and anticipates earning within its allowed ROE range in 2024. USD earnings for 2024 are expected to be significantly higher than in 2023 primarily due to higher revenue from new base rates in support of significant ongoing system investment and continued customer growth in 2024, which is expected to be consistent with Florida's population growth rates.

NMGC expects 2024 rate base growth to be higher than 2023, with slightly lower USD earnings as a result of increased operating expenses and lower asset optimization revenues, partially offset by higher revenue from expected new base rates, effective October 2024. NMGC anticipates earning near its authorized ROE in 2024. Customer growth is expected to be consistent with historical trends.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective in October 2024. 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 proposed 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 application for a certificate of public convenience and necessary for a liquified natural gas facility in New Mexico. The settlement is subject to NMPRC approval. The NMPRC is expected to rule on the settlement in Q3 2024.

In 2024, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $445 million USD (2023 – $495 million USD), including AFUDC. PGS and NMGC will make investments to maintain the reliability of their systems and support customer growth.

Other Electric Utilities

Other Electric Utilities' USD earnings in 2024 are expected to increase over the prior year due to higher sales volumes at BLPC.

On May 9, 2024, the Government of Bahamas passed the 'Electricity Bill 2024', subject to Royal Assent, to take effect June 1, 2024. The bill purports to remove the jurisdiction of the GBPA over GBPC and to have the Utilities Regulation and Competition Authority, another Bahamian regulator, regulate GBPC. Management is assessing the implications of the legislation, but do not foresee it having a material impact to Emera.

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 process is currently ongoing. Management does not expect the final decision and order to have a material impact on adjusted net income.

In 2024, capital investment in the Other Electric Utilities segment is expected to be approximately $80 million USD (2023 – $47 million USD), primarily in projects to support system reliability.

Other

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 within its guidance range of $15 to $30 million USD.

The adjusted net loss from the Other segment is expected to be higher in 2024 due to increased interest expense, higher Corporate OM&G, and a lower contribution to net income from Emera Energy primarily as a result of one-time investment tax credits at Bear Swamp in 2023.

The Other segment does not anticipate any significant capital investment in 2024.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

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

millions of dollars		Increase (Decrease)	Explanation
Assets			
Cash and cash equivalents	**$**	**(309)**	Decreased due to investment in property, plant and equipment ("PP&E"), net repayments under committed credit facilities at Corporate, and dividends paid on Emera common stock. These were partially offset by cash from operations
Derivative instruments (current and long-term)		**(53)**	Decreased due to reversal of 2023 contracts and changes in existing positions at EES as a result of lower natural gas prices, and settlements on derivative instruments in NSPI, partially offset by higher commodity prices and new derivative instruments at NSPI
Receivables and other assets (current and long-term)		**54**	Increased due to seasonal trends of the business at NSPI, new base rates that went into effect in 2024 at PGS, and higher gas transportation assets at EES. These were partially offset by lower accounts receivable as a result of lower natural gas prices at TEC, NMGC and EES
PP&E, net of accumulated depreciation and amortization		**786**	Increased due to capital additions in excess of depreciation and the effect of FX translation of Emera's non-Canadian affiliates
Goodwill		**144**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates
Liabilities and Equity			
Short-term debt and long-term debt (including current portion)	**$**	**178**	Increased due to issuance of long-term debt at TEC; the effect of FX translation of Emera's non-Canadian affiliates and proceeds from committed credit facilities at Emera and TECO Finance, Inc. ("TECO Finance"). These were partially offset by repayment of committed credit facilities at TEC and NSPI and repayment of debt at NMGC
Accounts payable		**(258)**	Decreased due to lower commodity prices at TEC, EES and NMGC
Deferred income tax liabilities, net of deferred income tax assets		**92**	Increased due to tax deductions in excess of accounting depreciation related to PP&E and the effect of FX translation of Emera's non-Canadian affiliates
Regulatory liabilities (current and long-term)		**99**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates, higher cost of removal at TEC, and higher deferrals related to derivative instruments at NSPI
Other liabilities (current and long-term)		**136**	Increased due to timing of interest payments at Corporate, TEC and PGS
Common stock		**103**	Increased due to shares issued
Accumulated other comprehensive income		**246**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates

OTHER DEVELOPMENTS

Appointments

Board of Directors

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 March 31 **2024**		2023
Operating revenues – regulated electric	**$**	**548**	$	552
Regulated fuel for generation and purchased power	**$**	**141**	$	146
Contribution to consolidated net income	**$**	**63**	$	79
Contribution to consolidated net income – CAD	**$**	**85**	$	107
Electric sales volumes (Gigawatt hours (“GWh”))		**4,350**		4,474
Electric production volumes (GWh)		**4,471**		4,590
Average fuel cost in dollars per megawatt hour (“MWh”)	**$**	**32**	$	32

The impact on Q1 2024 earnings related to the change in the FX rate was minimal.

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

For the millions of USD		Three months ended March 31
Contribution to consolidated net income – 2023	**$**	**79**
Decreased operating revenues primarily due to the impact of unfavourable weather of $13 million, pre-tax, partially offset by new base rates and customer growth		(4)
Decreased fuel for generation and purchased power due to lower natural gas prices		5
Increased OM&G, pre-tax, due to storm restoration cost recognition related to storm surcharge revenue ($6 million expense, offset in revenue), higher generation maintenance, and higher transmission and distribution expenses		(16)
Increased depreciation and amortization due to additions to facilities and generation projects placed in service		(8)
Decreased income tax expense due to decreased income before provision for income taxes and increased production tax credits related to solar facilities		7
Contribution to consolidated net income – 2024	**$**	**63**

Canadian Electric Utilities

For the millions of dollars (except as indicated)		Three months ended March 31 **2024**		2023
Operating revenues – regulated electric	**$**	**554**	$	504
Regulated fuel for generation and purchased power (1)	**$**	**290**	$	103
Contribution to consolidated net income	**$**	**87**	$	92
Electric sales volumes (GWh)		**3,183**		3,131
Electric production volumes (GWh)		**3,433**		3,354
Average fuel costs in dollars per MWh (2)	**$**	**84**	$	31

(1) Regulated fuel for generation and purchased power includes NSPI's FAM deferral on the Condensed Consolidated Statements of Income; however, it is excluded in the segment overview.
(2) Average fuel costs for the three months ended March 31, 2023, include a reversal of $166 million related to the Nova Scotia Cap-and-Trade Program.

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

For the millions of dollars	Three months ended March 31 **2024**	 2023
NSPI	**$ 57**	$ 68
Equity investment in LIL	**17**	16
Equity investment in NSPML	**13**	8
Contribution to consolidated net income	**$ 87**	$ 92

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

For the millions of dollars	Three months ended March 31
Contribution to consolidated net income – 2023	**$ 92**
Increased operating revenues due to new rates and increased residential sales volumes	50
Increased regulated fuel for generation and purchased power primarily due to reversal of the Nova Scotia Cap-and-Trade Program provision (1) in Q1 2023, higher commodity prices and increased sales volumes	(187)
Decreased FAM deferral primarily due to reversal of the Nova Scotia Cap-and-Trade Program provision (1) in Q1 2023, partially offset by under-recovery of fuel costs in 2024	151
Increased OM&G, pre-tax, due to higher transmission and distribution costs, a disallowance (2) under the FAM audit, and higher storm restoration and vegetation management costs. These were partially offset by the RER penalty recognized in Q1 2023	(16)
Increased income from equity investments at NSPML primarily due to the Maritime Link holdback recognized in Q1 2023	5
Increased income tax expense at NSPI due to decreased tax deductions in excess of accounting depreciation related to PP&E, partially offset by a decrease in the benefit of tax loss carryforwards recognized as a deferred income tax regulatory liability, and decreased income before provision for income taxes	(7)
Other	(1)
Contribution to consolidated net income – 2024	**$ 87**

(1) In Q1 2023, the Province provided NSPI with additional emissions allowances sufficient to achieve compliance with the 2019 through 2022 Nova Scotia Cap-and-Trade Program compliance period and accrued compliance costs related to the expected purchase of emissions credits were reversed, resulting in a fuel cost recovery of $166 million.
(2) On February 21, 2024, the UARB's decision on the FAM audit findings relating to fiscal 2020 and 2021 were released and included a disallowance of costs, net of tax and interest, of $3 million recorded in OM&G (the associated interest expense of $1 million is recorded in 'Interest expense, net').

Gas Utilities and Infrastructure

For the millions of USD (except as indicated)	Three months ended March 31 **2024**	 2023
Operating revenues – regulated gas (1)	**$ 391**	$ 422
Operating revenues – non-regulated	**4**	4
Total operating revenue	**$ 395**	$ 426
Regulated cost of natural gas	**$ 134**	$ 205
Contribution to consolidated net income	**$ 73**	$ 70
Contribution to consolidated net income – CAD	**$ 98**	$ 94
Gas sales volumes (millions of Therms)	**910**	930

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline for the three months ended March 31, 2024 (2023 – $11 million).

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

For the millions of USD	Three months ended March 31 **2024**	2023
PGS	**$ 42**	$ 26
NMGC	**22**	33
Other	**9**	11
Contribution to consolidated net income	**$ 73**	$ 70

The impact on Q1 2024 earnings related to the change in the FX rate was minimal.

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

For the millions of USD	Three months ended March 31
Contribution to consolidated net income – 2023	**$ 70**
Decreased gas revenues due to lower fuel revenues at NMGC, partially offset by new base rates at PGS	(23)
Decreased asset optimization revenues at NMGC	(8)
Decreased cost of natural gas due to lower natural gas prices at NMGC	71
Increased OM&G, pre-tax, primarily due to the timing of deferred clause recoveries at PGS and higher labour costs at PGS and NMGC	(12)
Increased depreciation primarily due to asset growth at PGS	(10)
Increased interest expense, net, pre-tax, primarily due to higher interest rates and increased borrowings to support ongoing operations and capital investments primarily at PGS	(10)
Other	(5)
Contribution to consolidated net income – 2024	**$ 73**

Other Electric Utilities.

For the millions of USD (except as indicated)	Three months ended March 31 **2024**	2023
Operating revenues – regulated electric	**$ 92**	$ 85
Regulated fuel for generation and purchased power	**$ 48**	$ 42
Contribution to consolidated adjusted net income	**$ 7**	$ 3
Contribution to consolidated adjusted net income – CAD	**$ 9**	$ 4
Equity securities MTM gain	**$ 1**	$ 1
Contribution to consolidated net income	**$ 7**	$ 4
Contribution to consolidated net income – CAD	**$ 10**	$ 6
Electric sales volumes (GWh)	**305**	283
Electric production volumes (GWh)	**327**	300
Average fuel costs in dollars per MWh	**147**	140

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

For the millions of USD	Three months ended March 31 **2024**	2023
BLPC	**$ 5**	$ 2
GBPC	**2**	2
Other	**-**	(1)
Contribution to consolidated adjusted net income	**$ 7**	$ 3

The impact on Q1 2024 earnings related to the change in the FX rate was minimal.

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

For the millions of USD		Three months ended March 31
Contribution to consolidated net income – 2023	**$**	**4**
Increased operating revenues – regulated electric primarily due to higher fuel revenue and higher sales volumes at BLPC		7
Increased regulated fuel for generation and purchased power as a result of higher fuel prices at BLPC		(6)
Other		2
Contribution to consolidated net income – 2024	**$**	**7**

Other

For the millions of dollars		Three months ended March 31 **2024**		 2023
Marketing and trading margin (1) (2)	**$**	**80**	$	95
Other non-regulated operating revenue		**9**		6
Total operating revenues – non-regulated	**$**	**89**	$	101
Contribution to consolidated adjusted net (loss) income	**$**	**(63)**	$	(29)
MTM (loss) gain, after-tax (3)		**(10)**		290
Contribution to consolidated net (loss) income	**$**	**(73)**	$	261

(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 pre-tax MTM gain of $1 million for the three months ended March 31, 2024 (2023 – $435 million gain).

(3) Net of income tax recovery of $4 million for the three months ended March 31, 2024 (2023 – $119 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 March 31 **2024**		 2023
Emera Energy				
EES	**$**	**45**	$	55
Other		**1**		1
Corporate – see breakdown of adjusted contribution below		**(103)**		(80)
Block Energy LLC		**(6)**		(4)
Other		**-**		(1)
Contribution to consolidated adjusted net (loss) income	**$**	**(63)**	$	(29)

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

For the millions of dollars		Three months ended March 31
Contribution to consolidated net income – 2023	**$**	**261**
Decreased marketing and trading margin due to lower natural gas prices, low volatility, and less favourable hedging opportunities		(15)
Increased OM&G, pre-tax, primarily due to the timing of long-term compensation hedges		(20)
Increased interest expense, pre-tax, primarily due to increased total debt		(8)
Increased income tax recovery, primarily due to increased losses before provision for income taxes		11
Decreased MTM gain, after-tax, primarily due to changes in existing positions partially offset by lower amortization of gas transportation assets at EES		(300)
Other		(2)
Contribution to consolidated net (loss) income – 2024	**$**	**(73)**

Corporate

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

For the millions of dollars	Three months ended March 31 **2024**	 2023
Operating expenses (1)	**$ (25)**	$ (6)
Interest expense	**(91)**	(82)
Income tax recovery	**33**	26
Preferred dividends	**(18)**	(16)
Other (2)(3)	**(2)**	(2)
Corporate adjusted net (loss) income (4)	**$ (103)**	$ (80)

(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, pre-tax, net loss of $1 million on FX hedges for the three months ended March 31, 2024 ($1 million after-tax), as discussed above (2023 – $3 million net loss, pre-tax and $2 million loss, after-tax).
(4) Excludes a MTM loss, after-tax, of $2 million for the three months ended March 31, 2024 (2023 – $5 million gain, after-tax).

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 $9 billion capital investment plan over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. Capital investments at Emera's regulated utilities are subject to regulatory approval.

Emera plans to use cash from operations, debt raised at the utilities, equity, and select asset sales 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, 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 credit facilities with varying maturities that cumulatively provide $5.1 billion of credit, with approximately $2.7 billion undrawn and available at March 31, 2024. The Company was holding a cash balance of $276 million at March 31, 2024. For further discussion, refer to the "Debt Management" section below.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the three months ended March 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		**631**		654		(23)
Change in working capital		**(62)**		(201)		139
Operating activities	**$**	**569**	$	453	$	116
Investing activities		**(604)**		(640)		36
Financing activities		**(288)**		153		(441)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**11**		4		7
Cash, cash equivalents, and restricted cash, end of period	**$**	**276**	$	302	$	(26)

Cash Flow from Operating Activities

Net cash provided by operating activities increased $116 million to $569 million for the three months ended March 31, 2024, compared to $453 million for the same period in 2023.

Cash from operations before changes in working capital decreased $23 million year-over-year. This decrease was due to increased fuel for generation and purchase power expense at NSPI, driven by the reversal of the Nova Scotia Cap-and-Trade Program provision in Q1 2023, and decreased earnings and lower fuel clause recoveries at TEC. This was partially offset by the favourable change in regulatory liabilities due to the 2023 gas hedge settlements at NMGC, and increased earnings at PGS.

Changes in working capital increased operating cash flows by $139 million year-over-year. This increase was due to the 2023 reversal of the Nova Scotia Cap-and-Trade accrual at NSPI in Q1 2023, favourable changes in cash collateral positions at NSPI, and timing of accounts payable payments at NSPI, TEC, and NMGC. These were partially offset by unfavourable changes in accounts receivable at NMGC due to the receipt of its 2023 gas hedge settlement, and unfavourable changes in cash collateral positions at EES.

Cash Flow from Investing Activities

Net cash used in investing activities decreased $36 million to $604 million for the three months ended March 31, 2024, compared to $640 million for the same period in 2023. The decrease was due to lower capital investment primarily at PGS, partially offset by higher capital investment primarily at TEC.

Capital investments, including AFUDC, for the three months ended March 31, 2024, were $610 million compared to $646 million for the same period in 2023. Details of the 2024 capital investment by segment are shown below:

- $368 million – Florida Electric Utility (2023 – $347 million);
- $112 million – Canadian Electric Utilities (2023 – $115 million);
- $116 million – Gas Utilities and Infrastructure (2023 – $170 million);
- $14 million – Other Electric Utilities (2023 – $11 million); and
- $nil – Other (2023 – $3 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $441 million to $288 million for the three months ended March 31, 2024, compared to cash provided by financing activities of $153 million for the same period in 2023. This increase was due to repayment of short-term debt at TEC, the 2023 proceeds of long-term debt at NSPI, and higher repayments of Emera's committed credit facilities. These were partially offset by issuance of long-term debt at TEC, lower repayments of committed credit facilities at NSPI, and higher proceeds from short-term debt at TECO Finance.

Contractual Obligations

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

millions of dollars	2024	2025	2026	2027	2028	Thereafter	Total
Long-term debt principal	$ 1,459	$ 267	$ 3,114	$ 706	$ 538	$ 12,534	$ 18,618
Interest payment obligations (1)	746	821	732	637	598	7,572	11,106
Transportation (2)	592	561	435	413	364	2,728	5,093
Purchased power (3)	209	254	272	321	322	3,514	4,892
Capital projects	866	151	78	9	-	-	1,104
Fuel, gas supply and storage	394	239	61	10	5	-	709
Asset retirement obligations	9	2	1	1	2	409	424
Pension and post-retirement obligations (4)	22	30	40	48	32	151	323
Equity investment commitments (5)	240	-	-	-	-	-	240
Other	99	150	58	50	36	223	616
	$ 4,636	$ 2,475	$ 4,791	$ 2,195	$ 1,897	$ 27,131	$ 43,125

(1) 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 March 31, 2024, including any expected required payment under associated swap agreements.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $133 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from Independent Power Producers or other utilities over varying contract lengths.
(4) The estimated contractual obligation 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.
(5) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation to the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In December 2023, the UARB approved the collection of up to $164 million from NSPI for the recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Emera has committed to obtain certain transmission rights for Nalcor, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets effective August 15, 2021 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to committed syndicated revolving and non-revolving bank lines of credit in either CAD or USD, per the table below as at March 31, 2024.

millions of Canadian dollars (unless otherwise indicated)	Maturity	Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2027	$ 900	$ 327	$ 573
TEC (in USD) – Unsecured committed revolving credit facility	December 2028	800	57	743
NSPI – Unsecured committed revolving credit facility	December 2027	800	310	490
Emera – Unsecured non-revolving facility	December 2024	400	400	-
Emera – Unsecured non-revolving facility	February 2025	400	200	200
Emera – Unsecured non-revolving facility	August 2024	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2028	400	265	135
NSPI – Unsecured non-revolving facility	July 2024	400	400	-
PGS (in USD) – Unsecured revolving facility	December 2028	250	27	223
TEC (in USD) – Unsecured revolving facility	April 2024	200	-	200
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	2	123
Other (in USD) – Unsecured committed revolving credit facilities	Various	21	10	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 March 31, 2024.

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

Florida Electric Utilities

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

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.

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 material changes in commercial terms from the prior agreement. This facility was classified as long-term debt at March 31, 2024.

Other

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.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2023 annual MD&A.

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)	0.50		24
Issued under the DRIP, net of discounts	1.54		70
Senior management stock options exercised and Employee Share Purchase Plan	0.19		9
Balance, March 31, 2024	**286.35**	**$**	**8,565**

(1) For the three months ended March 31, 2024, 498,553 common shares were issued under Emera's ATM program at an average price of $48.43 per share for gross proceeds of $24 million ($24 million net of after-tax issuance costs). As at March 31, 2024, an aggregate gross sales limit of $176 million remained available for issuance under the ATM program.

As at May 8, 2024 the amount of issued and outstanding common shares was 286.6 million.

If all outstanding stock options were converted as at May 8, 2024, an additional 3.8 million common shares would be issued and outstanding.

Preferred Stock

As at May 8, 2024, 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.

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 Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $42 million for the three months ended March 31, 2024 (2023 – $37 million). NSPML is accounted for as an equity investment and therefore, the 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 Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, non-regulated, totalled $4 million for the three months ended March 31, 2024 (2023 – $1 million).

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

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2023 annual MD&A.

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars		**March 31 2024**		December 31 2023
Regulatory Deferral:				
Derivative instrument assets (1)	**$**	**34**	$	16
Derivative instrument liabilities (2)		**(55)**		(76)
Regulatory assets (1)		**58**		88
Regulatory liabilities (2)		**(33)**		(17)
Net asset	**$**	**4**	$	11
HFT Derivatives:				
Derivative instrument assets (1)	**$**	**132**	$	202
Derivative instrument liabilities (2)		**(390)**		(421)
Net liability	**$**	**(258)**	$	(219)
Other Derivatives:				
Derivative instrument assets (1)	**$**	**21**	$	22
Derivative instrument liabilities (2)		**(16)**		(7)
Net asset	**$**	**5**	$	15

(1) Current and other assets.
(2) Current and long-term liabilities.

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars		Three months ended March 31 **2024**		 2023
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$**	**(5)**	$	66
HFT Derivatives:				
Non-regulated operating revenues	**$**	**160**	$	839
Other Derivatives:				
OM&G	**$**	**(8)**	$	11
Other income, net		**(3)**		3
Net gains (losses)	**$**	**(11)**	$	14
Total net gains	**$**	**144**	$	919

(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 recorded in inventory will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

As of March 31, 2024, the unrealized gain in accumulated other comprehensive income was $13 million, net of tax (December 31, 2023 – $14 million, net of tax). For the three months ended March 31, 2024, unrealized gains of $1 million (2023 – $1 million), have been reclassified into interest expense, net.

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. 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 of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design of the Company's DC&P and ICFR as at March 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 quarter ended March 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 unaudited condensed consolidated interim financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the 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, 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. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in Emera's 2023 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

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

Improvements to Income Tax Disclosures

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

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements disclosures.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q1 2024**	Q4 2023	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022
Operating revenues	**$ 2,018**	$ 1,972	$ 1,740	$ 1,418	$ 2,433	$ 2,358	$ 1,835	$ 1,380
Net income (loss) attributable to common shareholders	**$ 207**	$ 289	$ 101	$ 28	$ 560	$ 483	$ 167	$ (67)
Adjusted net income	**$ 216**	$ 175	$ 204	$ 162	$ 268	$ 249	$ 203	$ 156
EPS – basic	**$ 0.73**	$ 1.04	$ 0.37	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)
EPS – diluted	**$ 0.73**	$ 1.04	$ 0.37	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)
Adjusted EPS – basic	**$ 0.76**	$ 0.63	$ 0.75	$ 0.60	$ 0.99	$ 0.93	$ 0.76	$ 0.59

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.