Management's Discussion & Analysis

As at November 10, 2023

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the third quarter of, and year-to-date 2023 relative to the same periods in 2022; and its financial position as at September 30, 2023 relative to December 31, 2022. Throughout this discussion, "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments. 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 discussion and analysis should be read in conjunction with the Emera unaudited condensed consolidated interim financial statements and supporting notes as at and for the three and nine months ended September 30, 2023; and the Emera annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2022. Additional information related to Emera, including the Company's Annual Information Form, can be found on SEDAR+ at www.sedarplus.ca.

Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). 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 September 30, 2023, 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") (1)	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") (1)	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 ("NLPUB")
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 ("NURC")

(1) Effective January 1, 2023, Peoples Gas System ceased to be a division of TEC and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.

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” 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 forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information 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 forward-looking information 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 forward-looking information. 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; 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; 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; environmental risks; foreign exchange (“FX”); regulatory and government decisions, including changes to environmental, 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, such as the COVID-19 novel coronavirus pandemic; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information 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 forward-looking information 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 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 provides 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 a forecasted rate base growth range of approximately 7 per cent to 8 per cent through 2026. The capital investment plan, mainly focused in Florida, continues to include significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, and customer-focused technologies. Emera's capital investment plan is being funded primarily through internally generated cash flows, debt raised at the operating company level, 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 facing significant change and Emera is well positioned to respond to shifting customer demands, digitization, decarbonization, complex regulatory environments, and decentralized generation.

Customers are looking for more choice, better control, and enhanced reliability in a time where costs of decentralized generation and storage have become more competitive in some regions. Advancing technologies are transforming the way utilities interact with their customers and generate and transmit energy. In addition, climate change and extreme weather are shaping how utilities operate and how they invest in infrastructure. There is also an overall need to replace aging infrastructure and further enhance reliability. Emera will play a role in all of these trends. Emera's strategy is to fund investments in renewable energy and technology assets which protect the environment and benefit customers through fuel or operating cost savings.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the Maritime Link in Atlantic Canada, and the ongoing construction of solar generation and modernization of the Big Bend Power Station at TEC. Emera's utilities are also investing in reliability projects and replacing aging infrastructure. All of these projects demonstrate Emera's strategy of safely delivering cleaner, reliable, and affordable energy for its customers.

Building on its decarbonization progress, Emera is continuing its efforts by establishing 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 clear 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. Emera calculates the non-GAAP measures and ratios 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, and the impact of the 2022 NSPML unrecoverable costs.

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.

For further detail on these MTM adjustments, refer to the "Consolidated Financial Review", "Financial Highlights – Other Electric Utilities", and "Financial Highlights – Other" sections.

In February 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. The after-tax unrecoverable costs were recognized in "Income from equity investments" in Emera's Condensed Consolidated Statements of Income. Management believes excluding these unrecoverable costs from the calculation of adjusted net income better reflects the underlying operations in the period. For further details on the 2022 NSPML unrecoverable costs, refer to the "Financial Highlights – Canadian Electric Utilities" section.

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 2022 Annual MD&A.

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

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

For the millions of dollars (except per share amounts)	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Net income attributable to common shareholders	**$ 101**	$ 167	**$ 689**	$ 462
MTM (loss) gain, after-tax (1)	**(103)**	(36)	**55**	(132)
NSPML unrecoverable costs (2)	**-**	-	**-**	(7)
Adjusted net income	**$ 204**	$ 203	**$ 634**	$ 601
EPS – basic	**$ 0.37**	$ 0.63	**$ 2.53**	$ 1.75
Adjusted EPS – basic	**$ 0.75**	$ 0.76	**$ 2.33**	$ 2.27

(1) Net of income tax recovery of $40 million for the three months ended September 30, 2023 (2022 – $14 million recovery) and $24 million income tax expense for the nine months ended September 30, 2023 (2022 – $51 million recovery).
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Condensed Consolidated Statements of Income.

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 and the 2022 NSPML unrecoverable costs.

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

For the millions of dollars	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Net income (1)	**$ 118**	$ 184	**$ 738**	$ 510
Interest expense, net	**235**	184	**684**	503
Income tax (recovery) expense	**(34)**	2	**77**	31
Depreciation and amortization	**266**	238	**785**	698
EBITDA	**$ 585**	$ 608	**$ 2,284**	$ 1,742
MTM (loss) gain, excluding income tax	**(143)**	(50)	**79**	(183)
NSPML unrecoverable costs (2)	**-**	-	**-**	(7)
Adjusted EBITDA	**$ 728**	$ 658	**$ 2,205**	$ 1,932

(1) Net income is before Non-controlling interest in subsidiaries and Preferred stock dividends.
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Condensed Consolidated Statements of Income.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Earnings Impact of After-Tax MTM (Loss) Gain

MTM loss, after-tax increased $67 million to $103 million in Q3 2023, compared to $36 million in Q3 2022 primarily due to higher amortization of gas transportation assets partially offset by favourable changes in existing positions at Emera Energy Services ("EES"). Year-to-date, the 2022 MTM loss, after-tax of $132 million, decreased $187 million to a $55 million MTM gain, after-tax for the same period in 2023. The year-over-year change was primarily due to favourable changes in existing positions partially offset by higher amortization of gas transportation assets at EES.

Consolidated Financial Highlights

For the millions of dollars **Adjusted Net Income**	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Florida Electric Utility	**$ 228**	$ 199	**$ 512**	$ 472
Canadian Electric Utilities	**38**	39	**179**	176
Gas Utilities and Infrastructure	**23**	33	**155**	149
Other Electric Utilities	**17**	12	**31**	21
Other	**(102)**	(80)	**(243)**	(217)
Adjusted net income	**$ 204**	$ 203	**$ 634**	$ 601
MTM (loss) gain, after-tax	**(103)**	(36)	**55**	(132)
NSPML unrecoverable costs	**-**	-	**-**	(7)
Net income attributable to common shareholders	**$ 101**	$ 167	**$ 689**	$ 462

The following table highlights significant year-over-year changes in adjusted net income from 2022 to 2023:

For the millions of dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2022	**$ 203**	**$ 601**
Operating Unit Performance		
Increased earnings at TEC due to new base rates, the impact of a weaker CAD and customer growth driving higher load, partially offset by higher operating, maintenance and general expenses ("OM&G"), interest expense and depreciation	29	40
Increased income from equity investments at NSPML primarily due to the partial reversal of the Maritime Link holdback costs recognized in 2022 and a lower holdback recognized in 2023	8	6
Year-to-date earnings increased at NMGC due to new base rates and higher asset optimization revenue	(1)	23
Decreased earnings at PGS due to higher interest expense and depreciation, partially offset by customer growth. Year-over-year also decreased due to higher OM&G	(4)	(6)
Decreased earnings at NSPI due to higher OM&G, including storm costs, interest expense, and depreciation, partially offset by new base rates and increased sales volumes	(10)	(7)
Quarter-over-quarter earnings decreased at EES as a result of very strong margin results in Q3 2022 due to high natural gas pricing and volatility	(13)	(1)
Corporate		
Increased income tax recovery primarily due to increased losses before provision for income taxes	5	12
Increased interest expense, pre-tax	(12)	(42)
Other Variances	(1)	8
Adjusted net income – 2023	**$ 204**	**$ 634**

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

For the millions of dollars	Nine months ended September 30 **2023**	 2022
Operating cash flow before changes in working capital	**$ 1,813**	$ 806
Change in working capital	**5**	149
Operating cash flow	**$ 1,818**	$ 955
Investing cash flow	**$ (2,045)**	$ (1,685)
Financing cash flow	**$ 166**	$ 844

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

As at millions of dollars	**September 30 2023**	December 31 2022
Total assets	**$ 39,147**	$ 39,742
Total long-term debt (including current portion)	**$ 16,919**	$ 16,318

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended September 30 **2023**	 2022	 Variance	Nine months ended September 30 **2023**	 2022	 Variance
Operating revenues	**$ 1,740**	$ 1,835	$ (95)	**$ 5,591**	$ 5,230	$ 361
Operating expenses	**1,468**	1,496	28	**4,302**	4,321	19
Income from operations	**$ 272**	$ 339	$ (67)	**$ 1,289**	$ 909	$ 380
Interest expense, net	**$ 235**	$ 184	$ (51)	**$ 684**	$ 503	$ (181)
Net income attributable to common shareholders	**$ 101**	$ 167	$ (66)	**$ 689**	$ 462	$ 227
Adjusted net income	**$ 204**	$ 203	$ 1	**$ 634**	$ 601	$ 33
Weighted average shares of common stock outstanding (in millions)	**273.6**	266.6	7.0	**272.2**	264.3	7.9
EPS – basic	**$ 0.37**	$ 0.63	$ (0.26)	**$ 2.53**	$ 1.75	$ 0.78
EPS – diluted	**$ 0.37**	$ 0.63	$ (0.26)	**$ 2.53**	$ 1.74	$ 0.79
Adjusted EPS – basic	**$ 0.75**	$ 0.76	$ (0.01)	**$ 2.33**	$ 2.27	$ 0.06
Dividends per common share	**$ 0.6900**	$ 0.6625	$ 0.0275	**$ 2.0700**	$ 1.9875	$ 0.0825
Adjusted EBITDA	**$ 728**	$ 658	$ 70	**$ 2,205**	$ 1,932	$ 273

Operating Revenues

For Q3 2023, operating revenues decreased $95 million compared to Q3 2022 and, absent increased MTM loss of $101 million, increased $6 million. The increase was due to new base rates at TEC and NSPI; storm cost recovery surcharge revenue at TEC; and the impact of a weaker CAD. These increases were partially offset by lower fuel revenues at TEC, NMGC, NSPI and PGS; lower off-system sales at PGS; and decreased marketing and trading margin at EES.

Year-to-date in 2023, operating revenues increased $361 million compared to 2022 and, absent decreased MTM loss of $224 million, increased by $137 million. The increase was due to the impact of a weaker CAD; new base rates at TEC, NSPI and NMGC; storm cost recovery surcharge revenue at TEC; increased customer growth at TEC, NSPI and PGS; and increased asset optimization revenue at NMGC. These increases were partially offset by lower fuel revenues at TEC, NSPI, PGS, NMGC and BLPC; a change in fuel cost recovery methodology for an industrial customer at NSPI; and decreased off-system sales at PGS.

Operating Expenses

Operating expenses for Q3 2023 decreased $28 million and year-to-date 2023 decreased $19 million, compared to the same periods in 2022. The decreases in both periods were due to lower fuel expenses at TEC, PGS, NMGC and BLPC; partially offset by the impact of a weaker CAD; and higher OM&G at TEC primarily due to storm restoration costs recognized related to the storm cost recovery surcharge revenue and higher storm restoration costs at NSPI. Year-over-year decrease is also due to a change in fuel cost recovery methodology for an industrial customer, partially offset by the recognition of the Nova Scotia Renewable Electricity Regulations (“RER”) penalty at NSPI.

Interest Expense, Net

Interest expense, net for Q3 2023 increased $51 million and year-to-date 2023 increased $181 million, compared to the same periods in 2022. The increases in both periods were due to higher interest rates; higher borrowings to support capital investments and ongoing operations; and the impact of a weaker CAD.

Net Income and Adjusted Net Income

For Q3 2023, net income attributable to common shareholders, compared to Q3 2022, was unfavourably impacted by the $67 million increase in after-tax MTM losses. Absent the MTM changes, adjusted net income increased $1 million. The increase was primarily due to increased earnings at TEC and NSPML, and higher income tax recovery at Corporate. These were partially offset by decreased earnings at EES, NSPI and PGS; and increased Corporate interest expense due to higher interest rates and increased total debt.

Year-to-date 2023, net income attributable to common shareholders, compared to the same period in 2022, was favourably impacted by the $187 million decrease in after-tax MTM losses and by the $7 million in NSPML unrecoverable costs recognized in 2022. Absent these changes, adjusted net income increased $33 million. The increase was primarily due to increased earnings at TEC, NMGC and NSPML; the impact of a weaker CAD on the translation of Emera's non-Canadian affiliates; and higher income tax recovery at Corporate. These were partially offset by increased Corporate interest expense due to higher interest rates and increased total debt, and decreased earnings at NSPI and PGS.

EPS and Adjusted EPS – Basic

EPS – basic was lower in Q3 2023 due to the decreased earnings as discussed above and the impact of the increase in weighted average shares outstanding. Adjusted EPS – basic was lower in Q3 2023 primarily due to the impact of the increase in weighted average shares outstanding.

EPS and adjusted EPS – basic were higher year-to-date in 2023 due to increased earnings as discussed above, partially offset by the impact of the 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 2022 annual MD&A.

The relevant CAD/USD exchange rates for 2023 and 2022 are as follows:

	Three months ended September 30		Nine months ended September 30		Year ended December 31
For the	**2023**	2022	**2023**	2022	2022
Weighted average CAD/USD	**$ 1.34**	$ 1.35	**$ 1.34**	$ 1.30	$ 1.34
Period end CAD/USD exchange rate	**$ 1.35**	$ 1.37	**$ 1.35**	$ 1.37	$ 1.35

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

For the	Three months ended September 30		Nine months ended September 30	
millions of USD	**2023**	2022	**2023**	2022
Florida Electric Utility	**$ 170**	$ 153	**$ 381**	$ 367
Gas Utilities and Infrastructure (1)	**12**	19	**101**	98
Other Electric Utilities	**13**	9	**23**	16
Other segment (2)	**(32)**	(30)	**(77)**	(80)
Total (3)	**$ 163**	$ 151	**$ 428**	$ 401

(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) Net of $57 million MTM loss, after-tax for the three months ended September 30, 2023 (2022 – $22 million loss) and $43 million MTM gain, after-tax, for the nine months ended September 30, 2023 (2022 – $92 million loss).

The translation impact of the change in FX rates on foreign denominated earnings decreased net income by $9 million in Q3 2023 and increased net income by $33 million year-to-date, compared to the same periods in 2022. The translation impact of a weaker CAD on foreign denominated earnings increased adjusted net income by $5 million in Q3 2023 and $23 million year-to-date compared to the same periods in 2022. 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.

BUSINESS OVERVIEW AND OUTLOOK

There have been no material changes in Emera's business overview and outlook from the Company's 2022 annual MD&A except for the updates as disclosed below. Emera's year-to-date results have been impacted by macroeconomic conditions, specifically higher interest rates as well as other impacts of inflation. These macroeconomic 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 2022 annual MD&A. For details on Emera's reportable segments, refer to note 1 of the Q3 2023 unaudited condensed consolidated interim financial statements.

Florida Electric Utility

TEC anticipates earning within its ROE range in 2023. New base rates effective January 1, 2023, as a result of the 2021 settlement agreement, will result in higher 2023 USD earnings than in 2022. Normalizing 2022 for weather, TEC sales volumes in 2023 are projected to be higher than in 2022 due to customer growth. TEC expects customer growth rates in 2023 to be comparable to 2022, reflective of the current expected economic growth in Florida.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the previous approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge on April 2023 bills. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency by the FPSC and issuance of an order by the FPSC is expected by Q3 2024.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were $36 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings. TEC will determine the timing of the request for recovery of Hurricane Idalia costs at a future time.

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

In 2023, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2022 – $1.1 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization and storm hardening investments.

Canadian Electric Utilities

NSPI

NSPI anticipates earning below its allowed ROE range in 2023 and expects earnings and sales volumes to be higher in 2023 than 2022.

On October 31, 2023, NSPI submitted an application to the UARB to defer $25 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At September 30, 2023, the $25 million is deferred to “Other long-term assets”, pending UARB approval. A decision is expected from the UARB in 2024.

On September 16, 2023, Nova Scotia was struck by post-tropical storm Lee and as a result, approximately 280,000 customers lost power. The total cost of storm restoration was $19 million, with $10 million charged to OM&G, $5 million capitalized to property, plant and equipment (“PP&E) and $4 million deferred to the UARB approved storm rider. The storm rider for each of 2023, 2024, and 2025 allows NSPI to apply to the UARB for deferral and recovery of expenses if major storm restoration expenses exceed approximately $10 million in any given year. The application for deferral of the storm rider is made in the year following the year of the incurred costs, with recovery beginning in the year after the application.

On March 27, 2023, the UARB issued its final order approving the new electricity rates related to the General Rate Application settlement agreement between NSPI, key customer representatives and participating interest groups. The new electricity rates were effective on February 2, 2023.

Energy from renewable sources has increased due to the improved delivery of the NS Block of energy from Nalcor Energy’s (“Nalcor”) Muskrat Falls hydroelectric project (“Muskrat Falls”) to NSPI. For more information on the commissioning of LIL, refer to the “LIL” section below. For more information related to Nalcor’s delivery obligations of the NS Block of energy and the option for NSPI to purchase additional market-priced energy, refer to the “Business Overview and Outlook – Canadian Electric Utilities” section of Emera’s 2022 annual MD&A.

In 2023, NSPI’s capital investment is expected to be approximately $440 million (2022 – $540 million), including AFUDC. NSPI is investing primarily in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Regulation

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 2022 annual MD&A. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Nova Scotia Cap-and-Trade Program Regulations:
On March 16, 2023, the Province amended the Nova Scotia Cap-and-Trade Program Regulations, providing NSPI with additional emissions allowances sufficient to achieve compliance for the 2019 through 2022 compliance period. Accrued compliance costs of $166 million related to the anticipated purchase of emissions credits were reversed in Q1 2023. Credits NSPI purchased from provincial auctions in the amount of $6 million will not be refunded and NSPI does not anticipate further costs related to the Nova Scotia Cap-and-Trade Program.

Carbon Pricing Regulations:
In November 2022, the Province enacted amendments to the Environment Act which provided the framework for Nova Scotia to implement an output-based pricing system ("OBPS") to comply with the federal government's 2023 through 2030 carbon pollution pricing regulations, effective January 1, 2023. The federal government approved the Province's proposed system, however the OBPS will be subject to an interim review by the federal government of the standards effective for 2026. Although subsequent provincial regulations are required to detail how the OBPS will operate, the Province has shared preliminary standards with NSPI. The OBPS implements greenhouse gas ("GHG") emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards will be subject to a carbon price that starts at $65 per tonne in 2023 and will increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI's fuel adjustment mechanism ("FAM").

Nova Scotia Renewable Electricity Regulations ("RER"):
On April 6, 2023, the Province levied a $10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. The penalty was recorded in OM&G on the Condensed Consolidated Statements of Income. On May 26, 2023, NSPI initiated an appeal of the penalty through a proceeding with the UARB, as permitted under the RER. On October 12, 2023, the UARB decided that it will hear the appeal by giving due deference to the Province's decision but permitting the filing of new evidence to support the parties' positions. The preliminary hearing to determine the process and timeline of the proceeding is scheduled for November 14, 2023.

Other Legislation

Performance Standards Penalty Amendment:
On April 12, 2023, the Province enacted amendments to the Public Utilities Act which increased the cumulative total of administrative penalties that could be levied by the UARB against NSPI for non-compliance with current and future performance standards in a calendar year from $1 million to $25 million. Any administrative penalties levied against NSPI must be credited to customers and NSPI cannot recover administrative penalties imposed through rates.

Electricity Act Amendment:
On November 9, 2023, the Province passed amendments to the Electricity Act, subject to Royal Assent, which permit the Governor in Council to approve energy storage projects proposed by a public utility and owned wholly or in majority by the public utility if the project is in the best interest of ratepayers. Further, the amendments expand the ability of the Province to require NSPI to enter into power purchase agreements with renewable generation facilities by further empowering the Province to require NSPI to enter into an agreement for the sale of the electricity to specified customers. This would allow specified customers to buy renewable electricity from specified producers, with NSPI managing the transmission and sale of the energy.

Emera Newfoundland & Labrador Holdings Inc. ("ENL")

Total equity earnings from NSPML and LIL are expected to be higher in 2023, compared to 2022. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Condensed Consolidated Balance Sheets.

NSPML

In December 2022, NSPML received UARB approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2023, subject to a monthly holdback of up to $2 million, which will increase to $4 million beginning December 2023, as discussed below.

On October 4, 2023, the UARB issued its decision on the allocation and determination of the $18 million ($14 million related to 2022 and $4 million related to Q1 2023) of Maritime Link holdback. The UARB determined that all delivered NS Block energy, including make-up energy, be included in determining the amount of holdback. This results in $12 million of the previously recorded holdback to remain credited to customers through NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments", subject to a compliance filing. The UARB also confirmed that the holdback will cease once 90 per cent of deliveries are achieved for 12 consecutive months and the net outstanding balance of undelivered energy is less than 10 per cent of the contracted annual amount of the NS Block. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023. A final order by the UARB with respect to the compliance filing is expected in Q4 2023.

NSPML did not record additional holdback in Q3 2023, which is subject to UARB confirmation and the UARB granting relief in September relating to a planned outage of the LIL. For more information on the commissioning of the LIL, refer to the "LIL" section below.

On August 11, 2023, NSPML submitted an application to the UARB requesting recovery of approximately $164 million in Maritime Link costs for 2024. A decision is expected in Q4 2023.

NSPML does not anticipate any significant capital investment in 2023.

LIL

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

Upon issuance of the Commissioning Certificate, AFUDC equity earnings ceased and cash equity earnings and return of equity to Emera commenced.

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 to determine the amount of the remaining investment.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure 2023 USD earnings are anticipated to be consistent with 2022, primarily due to a base rate increase at NMGC, offset by slightly lower earnings at PGS, as discussed below.

PGS expects 2023 rate base growth to be consistent with 2022, with slightly lower USD earnings as a result of the effect of macroeconomic conditions, such as inflation and interest costs, which will more than offset higher revenue from new customers. As a result, PGS expects to earn below its allowed ROE range in 2023.

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

The 2020 PGS rate case settlement provides the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $26 million USD of accumulated depreciation through September 30, 2023, including $14 million USD reversed in 2022. The reversal of the remaining accumulated depreciation is expected to occur by December 31, 2023.

NMGC expects 2023 rate base and USD earnings to be higher in 2023 than 2022. Higher 2023 earnings are primarily due to base rate increases effective January 2023. NMGC anticipates earning near its authorized ROE in 2023 and expects customer growth rates to be consistent with historical trends.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new rates to become effective October 2024. NMGC requested a $49 million USD increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The case includes a requested ROE of 10.5 per cent. A final order from the NMPRC is expected by Q3 2024.

In 2023, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $500 million USD (2022 – $436 million USD), including AFUDC. PGS will make investments to expand and maintain its system and support customer growth. NMGC will continue to make investments to maintain the safety and reliability of its system and support customer growth.

Other Electric Utilities

Absent the impact of the GBPC impairment charge in Q4 2022, Other Electric Utilities' USD earnings in 2023 are expected to increase over the prior year primarily as a result of higher earnings due to higher base rates at BLPC.

On October 4, 2021, BLPC submitted a general rate review application to the FTC. On September 16, 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. On February 15, 2023, the FTC issued a decision on the BLPC rate review application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD and prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and a regulatory asset related to accumulated depreciation of $11 million USD. The FTC also requested a compliance filing before setting final rates which was submitted by BLPC on March 8, 2023. On March 7, 2023, BLPC filed a Motion for Review and Variation of FTC's decision and applied for a Stay of the Decision. The FTC determined that it would hear the Motion for Review by way of an oral hearing and parties were invited to submit and exchange written submissions on these matters during Q2 2023. On May 12, 2023, the FTC granted the Stay of the Decision until the determination of the Motion for Review and Variation. The Motion was heard in August 2023 and BLPC is awaiting FTC's decision. The final impacts to BLPC's rate base and final rates are not yet determinable and have not been recorded but management does not expect the final decision to have a material impact on Emera's adjusted net income. BLPC expects a final order from the FTC in Q4 2023.

In 2023, capital investment in the Other Electric Utilities segment is expected to be approximately $60 million USD (2022 – $48 million USD).

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 ($45 to $70 million USD of margin).

Absent the TECO Guatemala Holdings ("TGH") award in Q4 2022, the adjusted net loss from the Other segment is expected to be higher in 2023 due to increased interest expense, partially offset by decreased taxes due to a higher net loss. For details on the TGH award refer to the "Significant Items Affecting Earnings" section in Emera's 2022 annual MD&A.

The Other segment does not anticipate any significant capital investment in 2023.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2022 and September 30, 2023 include:

millions of dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ (56)**	Decreased due to investment in PP&E at the regulated utilities and dividends paid on common stock. These were partially offset by cash from operations, and proceeds from long-term debt issuances at NSPI
Inventory	**71**	Increased due to higher levels of fuel and materials inventory at NSPI and TEC and higher cost of fuel at NSPI, partially offset by lower commodity prices and natural gas volumes at EES
Derivative instruments (current and long-term)	**(117)**	Decreased due to settlements of derivative instruments and decreased pricing on power derivative instruments at NSPI, partially offset by the reversal of 2022 contracts and changes in existing positions at EES
Regulatory assets (current and long-term)	**(440)**	Decreased due to higher fuel clause recoveries at TEC and the reversal of accrued Cap-and-Trade emission compliance charges at NSPI. These were partially offset by increased FAM deferrals at NSPI due to an under-recovery of fuel costs and a change in fuel cost recovery methodology for an industrial customer, and higher deferred income tax regulatory asset at NSPI
Receivables and other assets (current and long-term)	**(1,249)**	Decreased due to lower gas transportation assets, decreased cash collateral and lower trade receivables as a result of lower commodity prices at EES, and settlement of the gas hedge receivable and seasonal trends at NMGC. These were partially offset by higher trade receivables at TEC
PP&E, net of accumulated depreciation and amortization	**1,219**	Increased due to capital additions in excess of depreciation and amortization

millions of dollars	Increase (Decrease)	Explanation
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ 541**	Issuance of debt at NSPI and proceeds from committed credit facilities at Emera, partially offset by net repayments under committed credit facilities at NSPI and repayment of debt at NMGC
Accounts payable	**(601)**	Decreased due to lower commodity prices at EES and NMGC, decreased cash collateral position on derivative instruments and lower fuel related payables at NSPI, and seasonal trends at NMGC
Deferred income tax liabilities, net of deferred income tax assets	**163**	Increased due to tax deductions in excess of accounting depreciation related to PP&E, partially offset by a decrease in net regulatory assets
Derivative instruments (current and long-term)	**(598)**	Decreased due to the reversal of 2022 contracts and changes in existing positions, partially offset by new contracts in 2023 at EES
Regulatory liabilities (current and long-term)	**(365)**	Decreased due to settlement of NMGC gas hedges and decreased deferrals related to derivative instruments at NSPI
Other liabilities (current and long-term)	**(54)**	Decreased due to the reversal of accrued Cap-and-Trade emissions compliance charges at NSPI partially offset by the timing of interest payments at TEC
Common stock	**231**	Increased due to shares issued
Retained earnings	**127**	Increased due to net income in excess of dividends paid

OTHER DEVELOPMENTS

Increase in Common Dividend

On September 20, 2023, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.87 from $2.76 per common share. The first payment will be effective November 15, 2023. Emera also extended its dividend growth rate target of four to five per cent through 2026.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 **2023**	2022	Nine months ended September 30 **2023**	2022
Operating revenues – regulated electric	**$ 795**	$ 753	**$ 2,024**	$ 1,926
Regulated fuel for generation and purchased power	**$ 210**	$ 270	**$ 520**	$ 631
Contribution to consolidated net income	**$ 170**	$ 153	**$ 381**	$ 367
Contribution to consolidated net income – CAD	**$ 228**	$ 199	**$ 512**	$ 472
Electric sales volumes (Gigawatt hours ("GWh"))	**6,919**	6,259	**16,529**	16,002
Electric production volumes (GWh)	**6,749**	6,341	**17,065**	16,675
Average fuel cost in dollars per megawatt hour ("MWh")	**$ 31**	$ 43	**$ 30**	$ 38

The impact of the change in the FX rate increased CAD earnings for the three and nine months ended September 30, 2023 by $6 million and $21 million, respectively.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2022	**$ 153**	**$ 367**
Increased operating revenues – regulated electric due to storm cost recovery surcharge revenue, new base rates and customer growth driving higher load, partially offset by changes in fuel recovery clause revenue	42	98
Decreased regulated fuel for generation and purchased power due to lower natural gas prices	60	111
Increased OM&G primarily due to storm restoration cost recognition related to the storm surcharge and timing of deferred clause recoveries	(53)	(111)
Increased depreciation and amortization due to additions to facilities and generation projects placed in service	(7)	(25)
Increased interest expense, net due to higher interest rates and higher borrowings to support capital investments and ongoing operations	(13)	(52)
Increased provincial, state and municipal taxes due to higher retail sales and higher taxable property placed in service	(11)	(25)
Decreased income tax expense primarily due to production tax credits related to solar facilities	-	13
Other	(1)	5
Contribution to consolidated net income – 2023	**$ 170**	**$ 381**

Canadian Electric Utilities

For the millions of dollars (except as indicated)	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Operating revenues – regulated electric	**$ 388**	$ 370	**$ 1,232**	$ 1,254
Regulated fuel for generation and purchased power (1)	**$ 213**	$ 239	**$ 543**	$ 777
Contribution to consolidated adjusted net income	**$ 38**	$ 39	**$ 179**	$ 176
NSPML unrecoverable costs	**$ -**	$ -	**$ -**	$ (7)
Contribution to consolidated net income	**$ 38**	$ 39	**$ 179**	$ 169
Electric sales volumes (GWh)	**2,331**	2,262	**7,777**	7,833
Electric production volumes (GWh)	**2,471**	2,397	**8,255**	8,320
Average fuel costs in dollars per MWh (2)	**$ 86**	$ 100	**$ 66**	$ 93

(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 nine months ended September 30, 2023 include the reversal of the $166 million of Nova Scotia Cap-and-Trade Program provision (2022 – $152 million expense).

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

For the millions of dollars	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
NSPI	**$ 10**	$ 20	**$ 101**	$ 108
Equity investment in LIL	**15**	14	**44**	40
Equity investment in NSPML (1)	**13**	5	**34**	28
Contribution to consolidated adjusted net income	**$ 38**	$ 39	**$ 179**	$ 176

(1) Excludes $7 million in NSPML unrecoverable costs, after-tax, for the nine months ended September 30, 2022.

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

For the millions of dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2022	**$**	**39**	**$**	**169**
Increased operating revenues − regulated electric quarter-over-quarter due to new rates and increased residential, commercial, and other sales volumes, partially offset by decreased industrial sales volumes. Year-over-year decrease primarily due to changes in fuel cost recovery methodology for an industrial customer(1), partially offset by quarter-over-quarter impacts noted above		18		(22)
Decreased regulated fuel for generation and purchased power primarily due to the reversal of the Nova Scotia Cap-and-Trade Program provision, compared to an expense in 2022, partially offset by increased commodity prices. Year-over-year decrease also partially offset by the Nova Scotia OBPS carbon tax accrual		26		234
Decreased FAM deferral primarily due to the reversal of the Nova Scotia Cap-and-Trade Program provision, partially offset by increased under-recovery of fuel cost and changes in the fuel recovery methodology for an industrial customer(1)		(14)		(143)
Increased OM&G quarter-over-quarter due to higher costs for storm restoration and vegetation management, year-over-year also due to recognition of the RER penalty at NSPI		(22)		(38)
Increased depreciation and amortization due to increased PP&E in service		(3)		(14)
Increased interest expense, net due to increased interest rates and higher debt levels		(9)		(29)
Increased income from equity investments primarily due to the partial reversal in 2023 of the Maritime Link holdback costs recognized in 2022 and a lower holdback recognized in 2023 at NSPML, and higher earnings from LIL		9		10
Increased income tax expense quarter-over-quarter at NSPI due to decreased tax deductions in excess of accounting depreciation related to PP&E and an increase in the benefit of tax loss carryforwards recognized as a deferred income tax regulatory liability		(11)		(2)
NSPML unrecoverable costs in 2022		-		7
Other		5		7
Contribution to consolidated net income – 2023	**$**	**38**	**$**	**179**

(1) For more information on the changes in fuel cost recovery methodology for an industrial customer, refer to note 6 in the Q3 2023 unaudited condensed consolidated interim financial statements

The Nova Scotia Cap-and-Trade Program provision related to the accrued cost of acquiring emissions credits for the 2019 through 2022 compliance period. As of December 31, 2022, NSPI had recognized a cumulative $166 million accrual in fuel costs related to the anticipated purchase of emissions credits and $6 million related to credits purchased from provincial auction. The accrued compliance costs of $166 million were reversed in Q1 2023 and NSPI does not anticipate further costs related to the Nova Scotia Cap-and-Trade Program. For further information on the reversal of this non-cash accrual and the FAM regulatory balance, refer to the “Business Overview and Outlook – Canadian Electric Utilities – NSPI” section and note 6 in the Q3 2023 unaudited condensed consolidated interim financial statements.

Gas Utilities and Infrastructure

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Operating revenues – regulated gas (1)	**$ 193**	$ 260	**$ 824**	$ 924
Operating revenues – non-regulated	**4**	4	**12**	10
Total operating revenue	**$ 197**	$ 264	**$ 836**	$ 934
Regulated cost of natural gas	**$ 44**	$ 115	**$ 292**	$ 433
Contribution to consolidated net income	**$ 17**	$ 25	**$ 115**	$ 117
Contribution to consolidated net income – CAD	**$ 23**	$ 33	**$ 155**	$ 149
Gas sales volumes (millions of Therms)	**705**	636	**2,333**	2,123

(1) Operating revenues – regulated gas includes $12 million of finance income from Brunswick Pipeline (2022 – $11 million) for the three months ended September 30, 2023 and $35 million (2022 – $34 million) for the nine months ended September 30, 2023.

Gas Utilities and Infrastructure's contribution is summarized in the following table:

For the millions of USD	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
PGS	**$ 13**	$ 16	**$ 58**	$ 65
NMGC	**(4)**	(4)	**29**	13
Other	**8**	13	**28**	39
Contribution to consolidated net income	**$ 17**	$ 25	**$ 115**	$ 117

The impact of the change in the FX rate increased CAD earnings for the three and nine months ended September 30, 2023 by $1 million and $8 million, respectively.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2022	**$ 25**	**$ 117**
Decreased operating revenues – regulated gas due to lower fuel revenues at PGS and NMGC, and off-system sales at PGS, partially offset by new base rates at NMGC and customer growth at PGS	(67)	(110)
Increased asset optimization revenue at NMGC	-	12
Decreased regulated cost of natural gas sold due to lower natural gas prices at PGS and NMGC	71	141
Increased OM&G year-over-year primarily due to higher labour and benefit costs, and timing of deferred clause recoveries at PGS	1	(10)
Increased depreciation and amortization expense due to asset growth at PGS and NMGC	(5)	(9)
Increased interest expense, net due to higher interest rates and increased borrowings to support ongoing operations and capital investments	(8)	(23)
Other	-	(3)
Contribution to consolidated net income – 2023	**$ 17**	**$ 115**

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 **2023**	2022	Nine months ended September 30 **2023**	2022
Operating revenues – regulated electric	**$ 108**	$ 104	**$ 286**	$ 300
Regulated fuel for generation and purchased power	**$ 57**	$ 58	**$ 147**	$ 169
Contribution to consolidated adjusted net income	**$ 13**	$ 9	**$ 23**	$ 16
Contribution to consolidated adjusted net income – CAD	**$ 17**	$ 12	**$ 31**	$ 21
Equity securities MTM loss	**$ (1)**	$ (1)	**$ -**	$ (5)
Contribution to consolidated net income	**$ 12**	$ 8	**$ 23**	$ 11
Contribution to consolidated net income – CAD	**$ 16**	$ 10	**$ 31**	$ 14
Electric sales volumes (GWh)	**344**	329	**937**	938
Electric production volumes (GWh)	**371**	356	**1,017**	1,015
Average fuel costs in dollars per MWh	**$ 154**	$ 163	**$ 145**	$ 167

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

For the millions of USD	Three months ended September 30 **2023**	2022	Nine months ended September 30 **2023**	2022
BLPC	**$ 6**	$ 3	**$ 14**	$ 6
GBPC	**7**	6	**11**	9
Other	**-**	-	**(2)**	1
Contribution to consolidated adjusted net income	**$ 13**	$ 9	**$ 23**	$ 16

The impact of the change in the FX rate on CAD earnings for the three months and nine months ended September 30, 2023 was minimal.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2022	**$ 8**	**$ 11**
Increased operating revenues – regulated electric quarter-over-quarter due to interim rates at BLPC. Decreased year-over-year due to lower fuel revenues at BLPC and the sale of Dominica Electricity Services Ltd. in Q1 2022, partially offset by interim rates at BLPC and increased sales volumes at GBPC	4	(14)
Decreased regulated fuel for generation and purchased power year-over-year due to lower fuel prices and changes in generation mix at BLPC	1	22
Decreased MTM loss on equity securities held at BLPC	-	5
Other	(1)	(1)
Contribution to consolidated net income – 2023	**$ 12**	**$ 23**

Other

For the millions of dollars		Three months ended September 30 **2023**		2022		Nine months ended September 30 **2023**		2022
Marketing and trading margin (1) (2)	**$**	**-**	$	24	**$**	**61**	$	71
Other non-regulated operating revenue		**7**		3		**22**		13
Total operating revenues – non-regulated	**$**	**7**	$	27	**$**	**83**	$	84
Contribution to consolidated adjusted net income (loss)	**$**	**(102)**	$	(80)	**$**	**(243)**	$	(217)
MTM (loss) gain, after-tax (3)		**(102)**		(34)		**55**		(125)
Contribution to consolidated net income (loss)	**$**	**(204)**	$	(114)	**$**	**(188)**	$	(342)

(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 $101 million in Q3 2023 (2022 – $32 million loss) and $85 million gain year-to-date (2022 – $149 million loss).
(3) Net of income tax recovery of $40 million for the three months ended September 30, 2023 (2022 – $14 million recovery) and $24 million income tax expense for the nine months ended September 30, 2023 (2022 – $51 million recovery).

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

For the millions of dollars		Three months ended September 30 **2023**		2022		Nine months ended September 30 **2023**		2022
Emera Energy	**$**	**3**	$	8	**$**	**39**	$	29
Corporate – see breakdown of adjusted contribution below		**(99)**		(84)		**(265)**		(230)
Block Energy LLC (1)		**(5)**		(3)		**(14)**		(13)
Other		**(1)**		(1)		**(3)**		(3)
Contribution to consolidated adjusted net income (loss)	**$**	**(102)**	$	(80)	**$**	**(243)**	$	(217)

(1) Previously Emera Technologies LLC

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

For the millions of dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income (loss) – 2022	**$**	**(114)**	**$**	**(342)**
Decreased marketing and trading margin quarter-over-quarter reflects very strong margin results in Q3 2022 due to high natural gas pricing and volatility. Year-over-year decrease reflects less favourable market conditions, specifically lower natural gas prices and volatility and higher fixed cost commitments for gas transportation in 2023 compared to 2022		(24)		(10)
Increased interest expense, pre-tax, due to higher interest rates and increased total debt		(13)		(43)
Increased income tax recovery primarily due to increased losses before provision for income taxes		19		19
Decreased MTM loss, after-tax quarter-over-quarter primarily due to higher amortization of gas transportation assets partially offset by favourable changes in existing positions at EES. Increased MTM gain, after-tax year-over-year primarily due to favourable changes in existing positions at EES and gains on Corporate FX hedges partially offset by amortization of gas transportation assets at EES		(66)		182
Other		(6)		6
Contribution to consolidated net income (loss) – 2023	**$**	**(204)**	**$**	**(188)**

Corporate

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

For the millions of dollars		Three months ended September 30 **2023**		2022		Nine months ended September 30 **2023**		2022
Operating expenses (1)	**$**	**32**	$	27	**$**	**66**	$	63
Interest expense		**84**		72		**241**		199
Income tax recovery		**(34)**		(29)		**(86)**		(74)
Preferred dividends		**16**		16		**48**		47
Other (2) (3)		**1**		(2)		**(4)**		(5)
Corporate adjusted net loss (4)	**$**	**(99)**	$	(84)	**$**	**(265)**	$	(230)

(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 $2 million ($1 million after-tax) for the three months ended September 30, 2023 (2022 – $1 million net loss, pre-tax and $1 million loss, after-tax) and a $7 million net loss, pre-tax ($5 million after-tax) for the nine months ended September 30, 2023 (2022 – $1 million net loss, pre-tax and $1 million loss, after-tax) on FX hedges, as discussed above.

(4) Excludes a MTM loss, after-tax, of $11 million for the three months ended September 30, 2023 (2022 – $22 million loss, after-tax) and a MTM gain, after-tax of $5 million for the nine months ended September 30, 2023 (2022 – $21 million loss, 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 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 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. The capital investment plan, mainly focused in Florida, continues to include significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, and customer-focused technologies. Capital investments at the 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 the issuance of preferred equity and the issuance of common equity through Emera’s DRIP and ATM programs.

Emera has credit facilities with varying maturities that cumulatively provide $5.5 billion of credit, with approximately $1.8 billion undrawn and available at September 30, 2023. The Company was holding a cash balance of $273 million at September 30, 2023. For further discussion, refer to the “Debt Management” section below. For additional information regarding the credit facilities, refer to notes 18 and 19 in the Q3 2023 unaudited condensed consolidated interim financial statements.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2023 and 2022 include:

millions of dollars		**2023**		2022		Change
Cash, cash equivalents, and restricted cash, beginning of period	**$**	**332**	$	417	$	(85)
Provided by (used in):						
Operating cash flow before changes in working capital		**1,813**		806		1,007
Change in working capital		**5**		149		(144)
Operating activities	**$**	**1,818**	$	955	$	863
Investing activities		**(2,045)**		(1,685)		(360)
Financing activities		**166**		844		(678)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**2**		18		(16)
Cash, cash equivalents, and restricted cash, end of period	**$**	**273**	$	549	$	(276)

Cash Flow from Operating Activities

Net cash provided by operating activities increased $863 million to $1,818 million for the nine months ended September 30, 2023, compared to $955 million for the same period in 2022.

Cash from operations before changes in working capital increased $1,007 million. This increase was due to higher fuel clause recoveries and higher storm cost recoveries at TEC, and decreased fuel for generation and purchased power expense at NSPI driven by the decreased Nova Scotia Cap-and-Trade Program provision. This was partially offset by a decrease in regulatory liabilities due to 2022 gas hedge settlements at NMGC.

Changes in working capital decreased operating cash flows by $144 million year-over-year. This decrease was due to the timing of accounts payable payments at NSPI and TEC, unfavourable changes in cash collateral positions at NSPI, decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges, and unfavourable change in fuel inventory at NSPI. This was partially offset by favourable changes in cash collateral positions at Emera Energy, and favourable changes in accounts receivable at NMGC due to the receipt of its 2022 gas hedge settlement.

Cash Flow from Investing Activities

Net cash used in investing activities increased $360 million to $2,045 million for the nine months ended September 30, 2023, compared to $1,685 million for the same period in 2022. The increase was due to higher capital investment in 2023.

Capital investments, including AFUDC, for the nine months ended September 30, 2023, were $2,090 million compared to $1,742 million for the same period in 2022. Details of the 2023 capital investment by segment are shown below:

- $1,212 million – Florida Electric Utility (2022 – $980 million);
- $346 million – Canadian Electric Utilities (2022 – $311 million);
- $482 million – Gas Utilities and Infrastructure (2022 – $405 million);
- $43 million – Other Electric Utilities (2022 – $43 million); and
- $7 million – Other (2022 – $3 million).

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $678 million to $166 million for the nine months ended September 30, 2023, compared to $844 million for the same period in 2022. This decrease was due to lower proceeds from long-term debt at TEC, lower proceeds from short-term debt at Emera and TECO Finance, higher repayments of committed credit facilities at NSPI, and lower issuance of common stock. This was partially offset by proceeds from long-term debt at NSPI, retirement of long-term debt at TEC in 2022, and higher net proceeds from committed credit facilities at Emera.

Contractual Obligations

As at September 30, 2023, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2023	2024	2025	2026	2027	Thereafter	Total
Long-term debt principal	$ 18	1,594	227	3,101	1,043	10,964	$ 16,947
Interest payment obligations (1)	343	791	744	655	556	7,395	10,484
Transportation (2)	199	642	498	414	398	2,999	5,150
Purchased power (3)	74	260	241	257	306	3,591	4,729
Fuel, gas supply and storage	314	590	218	65	5	1	1,193
Capital projects	655	234	25	5	-	-	919
Asset retirement obligations	6	2	2	3	1	413	427
Pension and post-retirement obligations (4)	10	30	30	82	59	170	381
Equity investment commitments (5)	-	240	-	-	-	-	240
Other	38	152	141	55	47	218	651
	$ 1,657	$ 4,535	$ 2,126	$ 4,637	$ 2,415	$ 25,751	$ 41,121

(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 September 30, 2023, 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 $137 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 (excluding the possibility of wind-up), 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. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be made in 2024.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In February 2022, the UARB issued its decision and Board Order approving NSPML’s requested rate base of approximately $1.8 billion. In December 2022, the UARB approved the collection of $164 million from NSPI for the recovery of Maritime Link costs in 2023. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

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

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

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 September 30, 2023.

millions of dollars	Maturity	Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2027	$ 900	$ 678	$ 222
TEC (in USD) – Unsecured committed revolving credit facility	December 2026	800	759	41
NSPI – Unsecured committed revolving credit facility	December 2027	800	317	483
Emera – Unsecured non-revolving facility	December 2023	400	400	-
Emera – Unsecured non-revolving facility	February 2024	400	-	400
Emera – Unsecured non-revolving facility	August 2024	400	400	-
TEC (in USD) – Unsecured non-revolving facility	December 2023	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	215	185
NSPI – Unsecured non-revolving facility	July 2024	400	400	-
TEC (in USD) - Unsecured revolving facility	February 2024	200	-	200
TEC (in USD) - Unsecured revolving facility	April 2024	200	-	200
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	80	45
NMGC (in USD) – Unsecured non-revolving facility	March 2024	45	45	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	21	8	13

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 September 30, 2023.

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

Florida Electric Utilities

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

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

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053. Proceeds from these issuances were added to the general funds of the Company and applied primarily to refinance existing indebtedness, to finance capital investment and for general corporate purposes.

Gas Utilities and Infrastructure

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033. Proceeds from the issuance were used to repay short-term borrowings. The $100 million USD that was repaid was classified as long-term debt at September 30, 2023.

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028. Proceeds from this issuance were used to repay GBPC's $28 million USD bond, which matured in May 2023.

Other

On August 18, 2023, Emera entered into a $400 million non-revolving term facility which matures on February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this facility will be used for general corporate purposes.

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

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030. The proceeds were used to repay Emera's $500 million unsecured fixed rate notes, which matured in June 2023.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2022 annual MD&A, with material updates as noted below:

NSPI renewed guarantees of $15 million USD with terms of varying lengths. As at September 30, 2023, NSPI had $109 million USD (2022 – $119 million USD) of guarantees outstanding with terms of varying lengths, all of which are issued on behalf of its subsidiary, NS Power Energy Marking Incorporated.

The Company has standby letters of credit and surety bonds in the amount of $80 million USD (December 31, 2022 – $145 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually, as required.

Outstanding Stock Data

Common Stock

Issued and outstanding:	millions of shares		millions of dollars
Balance, December 31, 2022	269.95	$	7,762
Issued under the DRIP, net of discounts	3.84		205
Senior management stock options exercised and Employee Share Purchase Plan	0.51		26
Balance, September 30, 2023	**274.30**	**$**	**7,993**

As at November 7, 2023, the amount of issued and outstanding common shares was 274.4 million.

If all outstanding stock options were converted as at November 7, 2023, an additional 3.1 million common shares would be issued and outstanding.

ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus (“Base Shelf”), primarily in support of the planned renewal of its ATM Program in Q4 2023 that will allow the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company’s discretion, at the prevailing market price. The ATM Program will be renewed upon the filing of a prospectus supplement to the Company’s Base Shelf and an equity distribution agreement. Once renewed, this ATM Program is expected to remain in effect until November 4, 2025.

Preferred Stock

As at November 7, 2023, 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 July 6, 2023, Emera announced that it would not redeem the 10 million outstanding Cumulative Rate Reset Preferred Shares, Series C (“Series C Shares”) or the 12 million outstanding Cumulative Minimum Rate Reset First Preferred Shares, Series H (“Series H Shares”) on August 15, 2023.

On August 4, 2023, Emera announced that after having taken into account all conversion notices received from holders, no Series C Shares were converted into Cumulative Floating Rate First Preferred Shares, Series D Shares and no Series H shares were converted into Cumulative Floating Rate First Preferred Shares, Series I shares. The holders of the Series C Shares are entitled to receive a dividend of 6.434 per cent per annum on the Series C Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.40213 per Series C Share per quarter). The holders of the Series H Shares are entitled to receive a dividend of 6.324 per cent per annum on the Series H Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.39525 per Series H Share per quarter).

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 $44 million for the three months ended September 30, 2023 (2022 – $41 million) and $122 million for the nine months ended September 30, 2023 (2022 – $118 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 – ENL" 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 $2 million for the three months ended September 30, 2023 (2022 – $1 million) and $10 million for the nine months ended September 30, 2023 (2022 – $7 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2023 and at December 31, 2022.

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 2022 annual MD&A.

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars	**September 30 2023**	December 31 2022
Regulatory Deferral:		
Derivative instrument assets (1)	**$ 86**	$ 238
Derivative instrument liabilities (2)	**(26)**	(25)
Regulatory assets (1)	**28**	30
Regulatory liabilities (2)	**(71)**	(230)
Net asset	**$ 17**	$ 13
HFT Derivatives:		
Derivative instrument assets (1)	**$ 186**	$ 153
Derivative instrument liabilities (2)	**(419)**	(1,025)
Net liability	**$ (233)**	$ (872)
Other Derivatives:		
Derivative instrument assets (1)	**$ 7**	$ 5
Derivative instrument liabilities (2)	**(35)**	(28)
Net liability	**$ (28)**	$ (23)

(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 September 30 **2023**	2022	Nine months ended September 30 **2023**	2022
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$ 6**	$ 51	**$ 70**	$ 142
HFT Derivatives:				
Non-regulated operating revenues	**$ 90**	$ (567)	**$ 907**	$ (635)
Other Derivatives:				
OM&G	**$ (20)**	$ (12)	**$ (12)**	$ (21)
Other income, net	**(18)**	(32)	**-**	(31)
Net losses	**$ (38)**	$ (44)	**$ (12)**	$ (52)
Total net gains (losses)	**$ 58**	$ (560)	**$ 965**	$ (545)

(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 at millions of dollars	September 30, 2023 **Interest rate hedge**	**FX forwards**	December 31, 2022 Interest rate hedge	FX forwards
Total unrealized gain in AOCI – net of tax	**$ 14**	**$ 1**	$ 16	$ -

For the three and nine months ended September 30, 2023, unrealized gains of $1 million (2022 – $1 million) and $2 million (2022 – $2 million) respectively, have been reclassified from accumulated other comprehensive income ("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. The Company's internal control framework is based on the 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 September 30, 2023, 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 September 30, 2023 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 2022 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"). ASUs issued by FASB, but which are not yet effective, were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the unaudited condensed consolidated interim financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q3 2023**	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Q4 2021
Operating revenues	**$ 1,740**	$ 1,418	$ 2,433	$ 2,358	$ 1,835	$ 1,380	$ 2,015	$ 1,868
Net income (loss) attributable to common shareholders	**$ 101**	$ 28	$ 560	$ 483	$ 167	$ (67)	$ 362	$ 324
Adjusted net income	**$ 204**	$ 162	$ 268	$ 249	$ 203	$ 156	$ 242	$ 168
EPS – basic	**$ 0.37**	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)	$ 1.38	$ 1.24
EPS – diluted	**$ 0.37**	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)	$ 1.38	$ 1.20
Adjusted EPS – basic	**$ 0.75**	$ 0.60	$ 0.99	$ 0.93	$ 0.76	$ 0.59	$ 0.92	$ 0.64

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.