Management's Discussion & Analysis

As at November 6, 2026

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as "Emera" or the "Company") during the third quarter of, and year-to-date, 2026 relative to the same periods in 2025; and its financial position as at September 30, 2026 relative to December 31, 2025. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera unaudited condensed consolidated interim financial statements and supporting notes as at and for the three and nine months ended September 30, 2026; and the Emera annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2025. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to Emera, including the Company's Annual Information Form, can be found on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.

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, 2026, Emera's rate-regulated subsidiaries and investments include:

Rate-Regulated Subsidiary or Equity Investment	**Accounting Policies Approved/Examined By**
Subsidiary	
Tampa Electric Company ("TEC")	Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC")
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Energy Board ("NSEB")
Peoples Gas System, Inc. ("PGS")	FPSC
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")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	NSEB
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
Wasoqonatl Transmission Incorporated ("WTI")	NSEB

On August 12, 2026, Emera completed the sale of New Mexico Gas Company, Inc. ("NMGC").

On May 12, 2026, Emera completed the sale of Grand Bahama Power Company Limited ("GBPC"). For further details on these items, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

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” within the meaning of applicable Canadian securities laws and “forward-looking statements” within the meaning of applicable US securities laws, including without limitation, the United States Private Securities Litigation Reform Act of 1995 (collectively, “FLI”), which reflect the current view with respect to the Company’s expectations regarding future growth, results of operations, performance, earnings, capital investment, sales volumes, recovery of costs, timing of regulatory decisions, the expected timing and completion of the CU Transaction (as defined herein) and the related expectation that the CU Transaction will be accretive to adjusted earnings per common share (“EPS”) in the first full year following closing, the expected pro-forma enterprise value and number of customers after the completion of the CU Transaction, the expected impact of the Cybersecurity Incident (as defined herein) on the Company’s financial position and results of operations, information technology (“IT”) systems restoration, insurance recoveries, and business continuity processes as well as other matters relating to the Cybersecurity Incident, business prospects and opportunities, and may not be appropriate for other purposes. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecast”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “targets”, “will”, “would” and similar expressions are often intended to identify FLI, although not all FLI contains these identifying words. The FLI reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

FLI is based on reasonable assumptions and is subject to risks, uncertainties, and other factors that could cause actual results to differ materially from historical results or results anticipated by the FLI. Factors that could cause results or events to differ from current expectations include, without limitation: the completion of the pending CU Transaction; regulatory and political risk; change in law risk; system operating and maintenance risks; uninsured risk; changes in economic conditions; commodity price and availability risk; liquidity and capital markets risk; general economic risk; changes in credit ratings; future dividend growth, rate base growth, and adjusted EPS growth; timing and costs associated with certain capital investments; expected impacts on Emera from challenges in the global economy; potential impacts of trade disputes and tariffs; estimated energy consumption rates; maintenance of adequate insurance coverage and receipt of proceeds; changes in customer energy usage patterns; developments in technology that could impact demand for electricity; climate risk; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; supply chain risk; environmental risks; foreign exchange ("FX"); regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with future employee benefit plan performance and funding requirements; loss of service area; risks and costs associated with failure of IT infrastructure and cybersecurity incidents including IT systems restoration and business continuity processes; uncertainties associated with infectious diseases, pandemics and similar public health threats; risks associated with health and safety; project development and land use rights risk; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on FLI, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the FLI. All FLI in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation and disclaims any intention to revise or update any FLI as a result of new information, future events or otherwise. Additional detailed information about the above referenced assumptions, risks, uncertainties and other factors is included in Emera's securities regulatory filings, which can be found on SEDAR+ at www.sedarplus.ca or on EDGAR at www.sec.gov.

INTRODUCTION AND STRATEGIC OVERVIEW

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

Emera's business strategy is centred on continued investment in its regulated utilities, combined with a focus on operational excellence and efficiency, to safely and reliably deliver energy to its 2.1 million customers. Effective execution of these priorities supports predictable and growing earnings, cash flow, and dividends for shareholders. Further, on October 6, 2026, Emera announced a pending business combination with ATCO Ltd. ("ATCO") and Canadian Utilities Limited ("CU"). For more information, refer to the "Other Developments" section.

Earnings opportunities in regulated utilities are a function of the magnitude of net investment in the utility (known as "rate base"), the amount of equity in the capital structure, and the targeted return on that equity ("ROE"), all as established and approved through regulation. Earnings are also affected by sales volumes and operating expenses. In 2025, Emera's regulated cost-of-service utilities in Florida accounted for 67 per cent of average consolidated rate base, with Atlantic Canada comprising 25 per cent, and the Caribbean and New Mexico 4 per cent each.

Emera's capital investment plan is forecasted to be approximately $21.5 billion from 2027 through 2031 and is focused on delivering value for customers through prudent investments in system reliability and resiliency, infrastructure expansion to support customer growth, renewable energy integration, and technology investments that strengthen operations and customer experience. It is anticipated that 82 per cent of this capital investment will be made in Emera's Florida utilities, necessitated by customer growth and system requirements at both TEC and PGS.

millions of dollars	2027	2028	2029	2030	2031	Total
Capital investment plan (1)(2)	$ 4,230	$ 4,370	$ 4,400	$ 4,310	$ 4,160	$ 21,470
Average consolidated rate base forecast (1)(2):						
US operations (3)	$ 25,200	$ 27,610	$ 30,020	$ 32,400	$ 34,740	
Canadian operations	7,710	8,340	8,650	8,940	9,100	
Total	$ 32,910	$ 35,950	$ 38,670	$ 41,340	$ 43,840	

(1) Capital investment plan and average consolidated rate base forecast are updated annually, typically in the second half of the year.
(2) Capital investment plan and average consolidated rate base forecast exclude the impact of the pending CU Transaction (as defined herein). For more information on the CU Transaction, refer to the “Other Developments” section.
(3) Includes Caribbean operations.

Emera’s capital investment plan will be funded primarily through internally generated cash flows, debt raised primarily at the operating company level consistent with regulated capital structures, equity issuances, and proceeds from the anticipated asset securitization in Atlantic Canada. Generally, Emera’s equity requirements are expected to be funded through the issuance of hybrid securities, and the issuance of common equity through Emera’s dividend reinvestment plan (“DRIP”) and its at-the-market program (“ATM program”). Maintaining investment-grade credit ratings is a core strategic priority of the Company.

Emera has increased dividends per common share paid for 20 consecutive years and has provided annual dividend growth guidance of one to two per cent. Emera anticipates average adjusted EPS growth of five to seven per cent through 2030, using 2024 as the base year, which will support continued reduction in the ratio of dividend payout to adjusted net income over time. For further information on the non-GAAP ratios “Adjusted EPS” and “Dividend Payout Ratio of Adjusted Net Income”, refer to the “Non-GAAP Financial Measures and Ratios” section.

NON-GAAP FINANCIAL MEASURES AND RATIOS

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

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

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

All periods: Gain on Sale of NMGC and Related Charges, after-tax
In Q3 2026, Emera completed the sale of NMGC and recognized a gain of $12 million after tax and transaction costs and additional charges related to the sale of $4 million, after-tax. In Q2 2025, the Company recognized a $71 million non-cash impairment charge, after-tax, and an additional loss of $1 million in estimated transaction costs, after-tax, related to the sale. For further details, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

2026: Charges Associated with the Pending CU Transaction, after-tax
On October 6, 2026, Emera announced the pending CU Transaction (as defined herein). In Q3 2026, Emera recognized associated costs of $5 million after-tax. For further details, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

2026: Loss on Sale of GBPC, after tax and transaction costs
In Q2 2026, Emera completed the sale of GBPC. For the three and nine months ended September 30, 2026, Emera recognized a loss on sale, after tax and transaction costs, of $5 million and $24 million, respectively. For further details, refer to the "Significant Items Affecting Earnings" and "Other Developments" sections.

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

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

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

Adjusted EPS – basic and dividend payout ratio of adjusted net income are non-GAAP ratios which are calculated using adjusted net income, as described above. For further details on dividend payout ratio of adjusted net income, see the "Dividend Payout Ratio" section in the Company's 2025 annual MD&A.

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

For the millions of dollars (except per share amounts)	Three months ended September 30 **2026**	2025	Nine months ended September 30 **2026**	2025
Net income attributable to common shareholders	**$ 182**	$ 228	**$ 849**	$ 946
Less:				
Gain (loss) on sale of NMGC and related charges, after-tax (1)	**8**	-	**8**	(72)
Charges associated with the pending CU Transaction, after-tax (2)	**(5)**	-	**(5)**	-
Loss on sale of GBPC, after tax and transaction costs (3)	**(5)**	-	**(24)**	-
MTM (loss) gain, after-tax (4)	**(76)**	(35)	**(17)**	140
Adjusted net income	**$ 260**	$ 263	**$ 887**	$ 878
EPS – basic	**$ 0.59**	$ 0.76	**$ 2.78**	$ 3.17
Adjusted EPS – basic	**$ 0.85**	$ 0.88	**$ 2.90**	$ 2.94

(1) Net of income tax expense of $23 million for the three and nine months ended September 30, 2026 (2025 - $5 million recovery)
(2) Net of income tax recovery of $2 million for the three and nine months ended September 30, 2026.
(3) Net of income tax expense of $1 million for the three months ended September 30, 2026 and $1 million income tax recovery for the nine months ended September 30, 2026.
(4) Net of income tax recovery of $30 million for the three months ended September 30, 2026 (2025 – $15 million recovery) and $6 million income tax recovery for the nine months ended September 30, 2026 (2025 – $56 million expense).

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital, and finance working capital requirements. Adjusted EBITDA represents EBITDA absent the income effect of the gain on sale of NMGC and related charges, charges associated with the pending CU Transaction, the loss on sale of GBPC and MTM adjustments.

Reconciliation of Net Income to EBITDA and Adjusted EBITDA

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Net income (1)	**$ 203**	$ 248	**$ 909**	$ 1,003
Interest expense, net	**250**	260	**796**	764
Income tax expense	**27**	6	**131**	116
Depreciation and amortization	**321**	324	**996**	959
EBITDA	**$ 801**	$ 838	**$ 2,832**	$ 2,842
Less (2):				
Gain (loss) on sale of NMGC and related charges	**30**	-	**30**	(77)
Charges associated with the pending CU Transaction	**(7)**	-	**(7)**	-
Loss on sale of GBPC	**(4)**	-	**(25)**	-
MTM (loss) gain	**(106)**	(50)	**(23)**	196
Adjusted EBITDA	**$ 888**	$ 888	**$ 2,857**	$ 2,723

(1) Net income is before preferred stock dividends.

(2) All adjustments exclude income tax

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Gain on Sale of NMGC and Related Charges

On August 12, 2026, Emera completed the sale of NMGC and recognized a gain, net of transaction costs, of $35 million ($12 million after tax and transaction costs, or $0.04 per common share) in "Other income, net" on the Condensed Consolidated Statements of Income and included in the "Other" segment. Emera recorded additional charges related to the sale of NMGC of $4 million, after-tax, or $0.01 per common share, in "OM&G" on the Condensed Consolidated Statements of Income and included in the "Gas Utilities and Infrastructure segment".

In Q2 2025, Emera recognized a non-cash impairment charge of $75 million ($71 million after-tax, or $0.24 per common share) related to the remeasurement of the NMGC disposal group to fair value ("FV") less costs to sell. This was recorded in "Impairment charge" on the Condensed Consolidated Statements of Income and included in the Other segment.

For further details on the sale of NMGC, refer to the "Other Developments" section and note 3 in the condensed consolidated interim financial statements.

Charges Associated with the Pending CU Transaction

On October 6, 2026, Emera announced the pending CU Transaction (as defined herein). In Q3 2026, Emera recognized associated costs of $7 million ($5 million after-tax or $0.02 per common share) in “OM&G” on the Condensed Consolidated Statement of Income and included in the Other segment. For further details, refer to the "Other Developments" section.

Loss on Sale of GBPC

On May 12, 2026, Emera completed the sale of GBPC. For the three and nine months ended September 30, 2026, Emera recognized a loss on sale, after tax and transaction costs of $5 million and $24 million, respectively. For further details, refer to the “Other Developments” section. This was recorded in “Other income, net” on the Condensed Consolidated Statements of Income and included in the “Other Electric Utilities” and “Other” segments.

As a result of the sale, earnings contributions from GBPC were $7 million lower in Q3 2026 and $14 million lower year-to-date 2026 compared to the same periods in 2025.

Earnings Impact of MTM (Loss) Gain, After-Tax

MTM loss, after-tax, increased $41 million to $76 million in Q3 2026 compared to $35 million in Q3 2025 primarily due to amortization of gas transportation assets and changes in existing positions at Emera Energy Services (“EES”). Year-to-date, MTM decreased $157 million to a $17 million loss in 2026 compared to a $140 million gain for the same period in 2025 primarily due to amortization of gas transportation assets, partially offset by changes in existing positions at EES.

Consolidated Financial Highlights

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
Adjusted Net Income	**2026**	2025	**2026**	2025
Florida Electric Utility	**$ 304**	$ 302	**$ 745**	$ 726
Canadian Electric Utilities	**17**	13	**119**	151
Gas Utilities and Infrastructure	**46**	32	**237**	200
Other Electric Utilities	**11**	16	**24**	28
Other	**(118)**	(100)	**(238)**	(227)
Adjusted net income	**$ 260**	$ 263	**$ 887**	$ 878
Gain (loss) on sale of NMGC, and related charges, after-tax	**8**	-	**8**	(72)
Charges associated with the pending CU Transaction, after-tax	**(5)**	-	**(5)**	-
Loss on sale of GBPC, after tax and transaction costs	**(5)**	-	**(24)**	-
MTM (loss) gain, after-tax	**(76)**	(35)	**(17)**	140
Net income attributable to common shareholders	**$ 182**	$ 228	**$ 849**	$ 946

The following table highlights significant quarter-over-quarter and year-over-year changes in adjusted net income from 2025 to 2026:

For the millions of dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2025	**$ 263**	**$ 878**
Operating Unit Performance		
Increased earnings at PGS due to higher revenue from new base rates and higher off-system sales, partially offset by higher operating, maintenance and general expenses ("OM&G"), depreciation and property taxes	17	49
Increased earnings at EES year-over-year due to favourable market conditions that led to higher natural gas prices and increased volatility that created profitable opportunities	5	31
Increased earnings quarter-over-quarter at NSPI due to lower interest expense, and higher revenue, partially offset by higher OM&G. Decreased earnings year-over-year due to higher OM&G, and lower income tax recovery as a result of higher clean technology investment tax credits in 2025, partially offset by lower interest expense, and higher sales volumes	4	(32)
Increased equity earnings, after-tax, at Bear Swamp year-over-year due to business interruption insurance received related to an unplanned outage in 2025 and higher generation	2	17
Increased earnings at TEC due to higher revenue from new base rates and higher off-system sales, partially offset by higher depreciation, OM&G, interest expense, state and municipality taxes, and a one-time reduction in recoverable fuel and purchased power costs of $10 million USD due to an FPSC-approved settlement agreement. Quarter-over-quarter earnings were also partially offset by unfavourable weather.	2	19
Decreased earnings at NMGC year-over-year due to higher OM&G	(2)	(14)
Decreased earnings at GBPC primarily due to the sale in Q2 2026	(7)	(9)
Corporate		
Increased income tax recovery year-over-year primarily due to an increased loss before provision for income taxes partially offset by an unfavourable deferred income tax asset valuation allowance adjustment	(2)	7
Increased interest expense, pre-tax, due to higher long-term debt resulting from the timing of financings, partially offset by interest earned on debt proceeds held in invested cash. Year-over-year is also partially offset by lower short-term debt	(3)	(31)
Increased OM&G, pre-tax, quarter-over-quarter primarily due to a loss on the long-term incentive hedge and increased costs as a result of New York Stock Exchange ("NYSE") listing. Year-over-year increase due to a lower gain on the long-term incentive hedge and higher costs associated with the NYSE listing	(17)	(30)
Other Variances	(2)	2
Adjusted net income – 2026	**$ 260**	**$ 887**

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

For the millions of dollars	Nine months ended September 30 **2026**	2025
Operating cash flow before changes in working capital	**$ 2,113**	$ 1,972
Changes in working capital	**315**	(382)
Operating cash flow	**$ 2,428**	$ 1,590
Investing cash flow	**$ (1,595)**	$ (2,518)
Financing cash flow	**$ (573)**	$ 941

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

As at millions of dollars	**September 30 2026**	December 31 2025
Total assets	**$ 45,626**	$ 44,817
Total long-term debt (including current portion) (1)	**$ 19,170**	$ 19,654

(1) Excludes NMGC balances classified as held for sale as at December 31, 2025. For further details refer to the "Other Developments" section and note 3 in the condensed consolidated interim financial statements.

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended September 30 **2026**	2025	Variance	Nine months ended September 30 **2026**	2025	Variance
Operating revenues	**$ 1,984**	$ 2,106	$ (122)	**$ 6,808**	$ 6,770	$ 38
Operating expenses	**1,581**	1,626	45	**5,108**	5,070	(38)
Income from operations	**$ 403**	$ 480	$ (77)	**$ 1,700**	$ 1,700	$ -
Other income, net	**$ 57**	$ 19	$ 38	**$ 63**	$ 135	$ (72)
Income tax expense	**$ 27**	$ 6	$ (21)	**$ 131**	$ 116	$ (15)
Net income attributable to common shareholders	**$ 182**	$ 228	$ (46)	**$ 849**	$ 946	$ (97)
Adjusted net income	**$ 260**	$ 263	$ (3)	**$ 887**	$ 878	$ 9
Weighted average shares of common stock outstanding (in millions)	**307.7**	299.9	7.8	**305.8**	298.5	7.3
EPS – basic	**$ 0.59**	$ 0.76	$ (0.17)	**$ 2.78**	$ 3.17	$ (0.39)
EPS – diluted	**$ 0.59**	$ 0.76	$ (0.17)	**$ 2.77**	$ 3.16	$ (0.39)
Adjusted EPS – basic	**$ 0.85**	$ 0.88	$ (0.03)	**$ 2.90**	$ 2.94	$ (0.04)
Dividends per common share declared	**$ 0.7325**	$ 0.7250	$ 0.0075	**$ 2.1975**	$ 2.1750	$ 0.0225
Adjusted EBITDA	**$ 888**	$ 888	$ -	**$ 2,857**	$ 2,723	$ 134

Operating Revenues

For Q3 2026, operating revenues decreased $122 million compared to Q3 2025 and, excluding the change in MTM impacts, decreased $46 million. The decrease was due to lower storm cost recovery revenue (offset in OM&G) and unfavourable weather at TEC; and lower revenue due the sale of NMGC in August 2026. These were partially offset by new base rates at TEC and PGS; the impact of a weaker CAD; and higher fuel cost recoveries at BLPC.

Year-to-date 2026, operating revenues increased $38 million compared to 2025 and, excluding the change in MTM impacts, increased $201 million. The increase was due to new base rates at TEC and PGS; increased marketing and trading margin at EES; increased commercial and industrial sales volumes at NSPI; and higher off-system sales at TEC and PGS. These were partially offset by the impact of a stronger CAD.

Operating Expenses

For Q3 2026, operating expenses decreased $45 million compared to Q3 2025. This decrease was due to lower storm costs recognition (offset in revenue) at TEC and NSPI and lower expenses due to the sale of NMGC in August 2026, partially offset by a one-time reduction in recoverable fuel and purchased power costs of $10 million USD at TEC due to an FPSC-approved settlement agreement.

Year-to-date operating expenses increased $38 million compared to 2025, and excluding charges related to the sale of NMGC in 2025, increased $113 million. These increases were due to increased OM&G due to higher labour and benefits at PGS and NMGC; increased depreciation expense at TEC, PGS and NSPI; higher OM&G at Corporate and NSPI; and a one-time reduction in recoverable fuel and purchased power costs of $10 million USD at TEC due to an FPSC-approved settlement agreement.

Other Income, net

Other income, net increased $38 million in Q3 2026, compared to the same period in Q3 2025. This increase was primarily due to the gain on the sale of NMGC in 2026.

Year-to-date, other income, net decreased $72 million compared to the same period in 2025. The decrease was due to the loss on sale of GBPC and FX losses, partially offset by the gain on sale of NMGC in 2026.

Income Tax Expense

For Q3 2026, income tax expense increased $21 million compared to Q3 2025 due to the gain on sale of NMGC and an unfavourable deferred income tax asset valuation allowance adjustment. This was partially offset by decreased earnings before provision for income taxes and increased tax credits recognized at TEC.

Year-to-date 2026, income tax expense increased $15 million compared to 2025 due to the gain on sale of NMGC, an unfavourable deferred income tax asset valuation allowance adjustment, decreased tax credits recognized at NSPI and the impact of a stronger CAD. This was partially offset by decreased earnings before provision for income taxes, the tax impact of charges related to the pending sale of NMGC in 2025 and increased tax credits recognized at TEC.

Net Income and Adjusted Net Income

For Q3 2026, net income attributable to common shareholders, compared to Q3 2025, was unfavourably impacted by a $41 million increase in MTM losses, after-tax, $5 million in charges related to the pending CU Transaction, after-tax, a $5 million loss on sale of GBPC, after tax and transaction costs and favourably impacted by an $8 million gain on sale of NMGC and related charges, after-tax in 2026. Excluding these impacts, adjusted net income decreased $3 million, primarily due to higher Corporate OM&G and interest expense and lower earnings due to the sale of GBPC. These were partially offset by increased earnings at PGS.

Year-to-date 2026, net income attributable to common shareholders, compared to the same period in 2025, was unfavourably impacted by a $157 million decrease in MTM gain, after-tax, a $24 million loss on sale of GBPC, after tax and transaction costs, and $5 million in charges related to the pending CU Transaction, after-tax, partially offset by an $8 million gain on sale of NMGC and related charges, after-tax in 2026 and $72 million after-tax impairment charges related to the sale of NMGC recognized in Q2 2025. Excluding these changes, adjusted net income increased $9 million. The increase was primarily due to increased earnings at PGS, EES and TEC; and higher equity earnings at Bear Swamp. These were partially offset by increased interest expense and higher OM&G at Corporate; lower earnings at NSPI; and lower earnings due to the sale of GBPC.

EPS – Basic and Adjusted EPS – Basic

For Q3 2026 and year-to-date, EPS – basic and adjusted EPS were lower due to the impact of lower earnings and higher 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 2025 annual MD&A.

The relevant CAD/USD exchange rates for 2026 and 2025 are as follows:

	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2026	2025	**2026**	2025	2025
Weighted average CAD/USD	**$ 1.40**	$ 1.38	**$ 1.38**	$ 1.41	$ 1.41
Period end CAD/USD exchange rate	**$ 1.42**	$ 1.39	**$ 1.42**	$ 1.39	$ 1.37

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

For the millions of USD	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Florida Electric Utility	**$ 217**	$ 220	**$ 537**	$ 522
Gas Utilities and Infrastructure (1)(2)	**31**	19	**159**	129
Other Electric Utilities (3)	**7**	11	**17**	20
Other segment (4)	**(35)**	(47)	**(83)**	(97)
Total (5)	**$ 220**	$ 203	**$ 630**	$ 574

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Excludes $3 million USD, after-tax, in charges related to the sale of NMGC for the three and nine months ended September 30, 2026.
(3) Excludes $3 million USD, after-tax loss for the three months ended September 30, 2026 and $15 million USD, after-tax loss on sale of GBPC for the nine months ended September 30, 2026.
(4) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(5) Excludes $56 million USD MTM loss, after-tax, for the three months ended September 30, 2026 (2025 – $20 million USD MTM loss, after-tax) and $2 million USD MTM gain, after-tax, for the nine months ended September 30, 2026 (2025 – $78 million USD MTM gain, after-tax).

In Q3 2026, the translation impact of a weaker CAD on USD denominated earnings increased adjusted net income by $2 million and increased net income attributable to common shareholders by $1 million, compared to the same periods in 2025. For the nine months ended September 30, 2026, the impact of a stronger CAD on US denominated earnings decreased adjusted net income by $15 million and decreased net income attributable to common shareholders by $42 million, compared to the same periods in 2025. These impacts include the effect of the FX hedges used to mitigate translation risk of USD earnings, which are included in Corporate in the Other segment.

BUSINESS OVERVIEW AND OUTLOOK

On October 6, 2026, Emera announced a pending business combination with ATCO and CU which is expected to be accretive to Emera's adjusted EPS in the first full year following its completion and result in transaction and integration related costs in 2026 and 2027. For more information on the transaction, refer to the "Other Developments" sections.

There have been no other material changes in Emera's business overview and outlook from the Company's 2025 annual MD&A, except for the updates disclosed below.

Florida Electric Utility

TEC anticipates earning within its allowed ROE range in 2026. USD earnings are expected to be higher in 2026 than 2025 as a result of new base rates effective January 1, 2026, and continued customer growth.

On September 3, 2026, TEC petitioned the FPSC to increase base revenue by $9 million USD to reflect the 2027 adjustment in accordance with the 2024 rate case decision. TEC expects the FPSC to reach a decision in Q4 2026.

On April 6, 2026, the FPSC established a docket for further study of certain purchased power costs recovered through the fuel adjustment clause. On April 15, 2026, TEC filed a petition with the FPSC seeking approval of revised depreciation rates for Bayside Station assets, which would decrease annual depreciation expense by approximately $20 million USD. On June 16, 2026, TEC and the Office of Public Counsel filed with the FPSC a motion to approve a settlement agreement for the revised depreciation rates to be effective on July 1, 2026. As part of the settlement agreement, TEC agreed to decrease fuel clause recovery by $10 million USD in 2026, which will be reflected on customer's bills in 2027. TEC also agreed to not seek approval for an increase in base revenues effective prior to January 1, 2028, except for previously approved subsequent year adjustments from the 2024 rate case and large load customer tariffs required by statute. On August 4, 2026, the FPSC approved the settlement agreement.

On February 3, 2025, the FPSC issued the final order approving the 2024 rate case decision, effective January 1, 2025. In March 2025, two intervening parties each filed a notice of appeal to the Florida Supreme Court regarding the outcome of TEC's 2024 base rate proceeding. On January 12, 2026, the intervening parties filed their briefs related to the appeal. On April 13, 2026, the FPSC and TEC filed responses to the briefs. On October 7, 2026, the Florida Supreme Court heard oral arguments. To date, the Florida Supreme Court has not made a decision regarding this case.

In 2026, capital investment in the Florida Electric Utility segment is expected to be $1.8 billion USD (2025 – $1.6 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include investment in generation reliability projects, storm hardening, grid modernization, and transmission expansion.

Canadian Electric Utilities

NSPI

NSPI expects earnings in 2026 to be higher than 2025 as a result of new base rates effective May 1, 2026, as discussed below, but anticipates earning below its allowed ROE range in 2026 primarily due to a delay in the general rate application ("GRA") decision. Sales volumes are expected to be higher in 2026 than in 2025.

Securitization Application:
On October 9, 2026, NSPI applied to the NSEB for a financing order authorizing the securitization of $1 billion of certain thermal generation, fuel related and certain other regulatory assets ('Proposed Securitized Assets") and the recovery of the Proposed Securitized Assets through a customer surcharge and cost recovery rider ("Securitization Rider"). For full details of the Proposed Securitized Assets refer to note 6 of the unaudited condensed consolidated interim financial statements. The securitization transaction is expected to reduce overall customer costs relative to traditional financing methods. NSPI requested the implementation of the Securitization Rider to begin on January 1, 2027, on an interim basis subject to an annual rate-setting application. NSPI expects a decision by the end of Q4 2026.

Performance-based Regulation Review:
On October 1, 2026, the Province enacted Bill 263 - Performance-based Regulation Review Act. This legislation requires the NSEB to review NSPI's cost-of-service regulatory model and assess whether, and in what manner, a performance-based regulation model could be applied to NSPI. On October 29, 2026, the NSEB initiated a review process which NSPI will participate in to help examine the potential benefits, risks, and impacts of this approach.

GRA:
On April 30, 2026, the NSEB approved the GRA with changes effective on May 1, 2026. This results in an average annual customer rate increase of 1.2 per cent, and a further average annual increase of 2.5 per cent on January 1, 2027. The approved rates are expected to result in annual revenue (fuel and non-fuel) increases of $31 million in 2026 and $97 million in 2027. Any under or over-recovery of fuel costs will be addressed through the NSPI's established fuel adjustment mechanism ("FAM") process with the NSEB. NSPI's ROE range will continue to be 8.75 per cent to 9.25 per cent, based on a common equity component of up to 40 per cent. The NSEB also approved the depreciation study completed in 2025 and continuation of the storm rider for each of 2026 and 2027. Additionally, the NSEB approved deferral of depreciation and financing costs for assets within the scope of NSPI's Decarbonization Deferral Account as of December 31, 2025 ("Securitization Deferral").

In 2026, capital investment is expected to be approximately $600 million (2025 – $712 million), including AFUDC. NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

NSPML

Equity earnings from NSPML in 2026 are expected to be generally consistent with 2025. The NSPML investment is recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

On October 21, 2026 the NSEB issued its decision on the holdback mechanism review, concluding that NSPML has satisfied the conditions to terminate the holdback mechanism as of May 1, 2024, and that all amounts withheld since that date are to be released to the Company.

On June 25, 2026, NSPML submitted an application to the NSEB requesting recovery of $200 million in 2027 and $192 million in 2028 for costs associated with the Maritime Link. A decision is expected by the end of Q4 2026.

On May 11, 2026, the NSEB issued its decision on NSPML's 2026 assessment application, reducing NSPML's approved regulated ROE from 9.0 per cent to 8.75 per cent and approved the collection of up to $198 million in Maritime Link costs for 2026.

In 2026, capital investment at NSPML is expected to be approximately $18 million (2025 – $7 million).

Gas Utilities and Infrastructure

PGS

PGS anticipates earning within the upper end of its allowed ROE range in 2026. USD earnings are expected to be higher in 2026 than 2025, as a result of new base rates effective January 1, 2026, favourable market conditions for off system sales revenue and continued customer growth.

On September 10, 2026, PGS's $25 million subsequent year adjustment was approved by the FPSC, with new rates effective January 1, 2027.

In 2026, capital investment is expected to be approximately $405 million USD (2025 – $323 million USD), including AFUDC. PGS will make investments to maintain the reliability of their systems and support customer growth.

NMGC

On August 12, 2026 Emera completed the sale of NMGC. For more information on the transaction, refer to the “Significant Items Impacting Earnings” and “Other Developments” sections.

Other Electric Utilities

On May 12, 2026, Emera completed the sale of GBPC. For further details, refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

Other Electric Utilities’ USD adjusted earnings in 2026 are expected to be lower than 2025 due to the sale of GBPC.

In November 2025, the Government of Barbados and BLPC agreed to new Transmission, Distribution, Sales and Dispatch (“T&D”) and Generation and Energy Storage (“G&S”) licenses. On May 11, 2026, BLPC’s new licenses became effective after the repeal of the previous license. The G&S license is valid until 2047, unless otherwise extended. The T&D License is valid for 30 years.

The next hearing of BLPC’s appeal of certain aspects of the FTC’s 2023 decisions is scheduled to be heard in Q4 2026.

In 2026, capital investment in the Other Electric Utilities segment is expected to be approximately $55 million USD (2025 – $67 million USD), including AFUDC, primarily in projects to support system reliability.

Other

The adjusted net loss from the Other segment is expected to be higher than 2025. Higher Corporate OM&G and interest expense are expected to be partially offset by higher contributions from EES, as discussed below.

Earnings from EES are generally dependent on market conditions. In particular, volatility in natural gas and electricity markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 usually providing the greatest opportunity for earnings. EES is generally expected to deliver annual adjusted net income of $15 million USD to $30 million USD. However, in light of strong market conditions in Q1 2026, EES expects adjusted net income for 2026 to be $60 million USD to $80 million USD.

In 2026, capital investment in the Other segment is expected to be approximately $6 million (2025 – $6 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2025 and September 30, 2026 include:

millions of dollars	Total Increase (Decrease)	Explanation of Increase (Decrease)
Assets		
Cash and cash equivalents	**$ 251**	Increased due to net proceeds from sale of NMGC, proceeds from issuance of long-term debt at Emera US Finance, LLC ("Emera Finance"), and higher cash from operations. These were partially offset by investment in Property, Plant and Equipment ("PP&E"), dividends paid on common stock, and repayment of debt
Restricted cash	**91**	Increased due to timing of cash held in trust related to debt interest payments
Regulatory assets (current and long-term)	**(51)**	Decreased due to lower storm costs recovery assets at TEC, and the sale of GBPC. These were partially offset by increased deferred income tax regulatory asset and deferrals related to the fuel adjustment mechanism ("FAM") at NSPI
Receivables and other assets (current and long-term)	**362**	Increased due to higher trade receivables at TEC, higher gas transportation assets at EES, and the effect of FX translation of Emera's non-Canadian affiliates. These were partially offset by sale of GBPC
Assets held for sale (current and long-term), net of liabilities (1)	**(872)**	Decreased due to sale of NMGC
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization	**2,174**	Increased due to capital additions in excess of depreciation and the effect of FX translation of Emera's non-Canadian affiliates, partially offset by the sale of GBPC
Goodwill	**196**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ 124**	Increased due to issuance of long-term debt at Emera US Finance, LLC ("Emera Finance") and PGS, and the effect of FX translation of Emera's non-Canadian affiliates. These were partially offset by repayment of long-term debt at Emera US Finance LP ("Emera US Finance"), repayment of debt at Emera, and the sale of GBPC
Accounts payable	**(182)**	Decreased due to lower trade accounts payable as a result of lower commodity prices at EES and the sale of GBPC. These were partially offset by timing of property taxes payable at TEC
Deferred income tax liabilities, net of deferred income tax assets	**245**	Increased due to tax deductions in excess of accounting depreciation related to PP&E, and the effect of FX translation of Emera's non-Canadian affiliates. This was partially offset by a decrease in net regulatory assets, and increased tax credits at TEC
Derivative instruments (current and long-term)	**561**	Increased due to new contracts and changes in existing positions at EES
Regulatory liabilities (current and long-term)	**158**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates, higher storm reserve regulatory liability at TEC, and increased deferrals related to derivative instruments at NSPI
Other liabilities (current and long-term)	**340**	Increased due to timing of interest payments at Corporate, timing of sales tax payments at EES, and the effect of FX translation of Emera's non-Canadian affiliates
Common stock	**440**	Increased due to shares issued
Accumulated other comprehensive income	**359**	Increased due to the effect of FX translation of Emera's non-Canadian affiliates partially offset by unrealized losses on net investment hedges
Retained earnings	**178**	Increased due to net income in excess of dividends paid

OTHER DEVELOPMENTS

Pending CU Transaction

On October 6, 2026, Emera announced a pending business combination with ATCO (TSX: ACO.X) and CU (TSX: CU) under which Emera will acquire all outstanding shares of ATCO and CU (other than CU shares held by ATCO) in a predominantly all-share transaction valued at approximately $14.3 billion, by way of a statutory arrangement under section 192 of the *Canada Business Corporations Act* (herein considered the "CU Transaction"). Immediately before the CU Transaction, ATCO's industrial services businesses will be spun-out into a new publicly traded company ("New ATCO").

Under the terms of the arrangement agreement, Emera will acquire all of the issued and outstanding shares of CU and ATCO for the following consideration:

- Canadian Utilities Class A shareholders, other than ATCO, will receive 0.755x of an Emera common share for each Canadian Utilities Class A share held;
- Canadian Utilities Class B shareholders, other than ATCO, will receive 0.819x of an Emera common share for each Canadian Utilities Class B share held;
- ATCO Class I and Class II shareholders ("ATCO Shareholders") will receive 0.865x of an Emera common share for each Class I or Class II share held. This exchange ratio reflects (i) the same 0.755x exchange ratio for the Canadian Utilities Class A shares held by ATCO; and (ii) the same 0.819x exchange ratio for the Canadian Utilities Class B shares held by ATCO, as adjusted for certain liabilities assumed by Emera and the value of certain Emera shares that will be issued to New ATCO as part of the spinoff transaction.
- In addition to the Emera shares, ATCO Shareholders will also receive one New ATCO Class I share for each ATCO Class I share held and one New ATCO Class II share for each ATCO Class II share held.

Upon completion of the CU transaction, current Emera shareholders are expected to own 60.8 per cent of the Company, with the transaction expected to be accretive to adjusted EPS in the first full year following closing.

CU is a diversified utility and energy infrastructure company with regulated electricity and natural gas transmission and distribution operations. CU's holdings include: ATCO Energy Systems, an integrated regulated electric utility which serves more than 1.6 million customers in Western Canada; ATCO Australia, primarily a regulated gas distribution utility which serves more than 800,000 customers across Western Australia; and ATCO EnPower, a non-regulated energy and infrastructure business. Upon completion of the CU Transaction, Emera is expected to have approximately $72 billion in pro-forma enterprise value and more than 6 million electric and gas customers (including approximately 1.5 million customers served by LUMA Energy, a joint venture of ATCO and Quanta Services Inc.).

The closing of the CU Transaction, which is expected to occur in Q3 or Q4 2027 or earlier, is subject to Emera shareholder approval, ATCO and CU securityholder approvals, certain court, regulatory and stock exchange approvals, and the satisfaction of other closing conditions.

Following the close of the CU Transaction, Emera's Board of Directors will consist of thirteen members, six of whom will be individuals proposed by ATCO and CU and seven of whom will be individuals proposed by Emera. Nancy Southern will serve as Co-Chair of the Emera Board with current Chair, Karen Sheriff.

Increase in Common Dividend

On October 2, 2026, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.96 from $2.93 per common share. The first payment will be effective November 13, 2026.

Sale of NMGC

On August 12, 2026 Emera completed the sale of NMGC for a total enterprise value of $1.74 billion ($1.25 billion USD), including cash proceeds of $940 million ($675 million USD), transferred debt and a working capital adjustment. Emera recognized a gain on sale of $35 million, after transaction costs ($12 million after tax and transaction costs, or $0.04 per common share). This was recorded in “Other income, net” on the Condensed Consolidated Statements of Income and included in the “Other” segment. Proceeds from the sale are being used to support capital investment opportunities within Emera’s regulated utilities and to reduce corporate debt.

Subsequent to receiving the final order approving the transaction from the New Mexico Public Regulation Commission ("NMPRC"), two notices of appeal challenging the NMPRC's final order were filed by intervening parties with the New Mexico Supreme Court. On October 27, 2026 the Court issued a briefing schedule for one of the appeals, establishing deadlines into Q1 2027. In the other appeal, on November 3, 2026, the Court granted the NMPRC's motion to advance a threshold issue seeking judicial determination of the legal framework applicable to NMPRC review of utility acquisitions, and set an accelerated briefing schedule on that issue. A decision on the threshold issue is expected in 2027. The outcome of the appeal process remains uncertain.

NMGC’s assets and liabilities were classified as held for sale beginning Q3 2024. The Company continued to record depreciation on these assets through the transaction closing date, as the depreciation continued to be reflected in customer rates and was reflected in the carryover basis of the assets on close. Depreciation and amortization of $144 million ($104 million USD) was recorded from August 5, 2024, the date they were classified as held for sale, until the date of the sale on August 12, 2026. Of the $144 million ($104 million USD) recorded to date, $47 million ($34 million USD) was recorded in 2026. NMGC’s assets and liabilities were previously included in Emera’s Gas Utilities and Infrastructure segment.

Sale of GBPC

On May 12, 2026, Emera completed the sale of its 100 per cent interest in GBPC. In Q2 2026, as a result of the sale, Emera recognized a loss of $21 million after transaction costs ($19 million after tax and transaction costs). In Q3 2026, an adjustment of $5 million after-tax was recognized as a result of finalizing the loss calculation, such that the final year-to-date loss on sale of GBPC was $25 million after transaction costs ($24 million, after tax and transaction costs, or 0.08 per common share). This was recorded in “Other income, net” on the Condensed Consolidated Statements of Income and included in the “Other Electric Utilities” and “Other” segments.

Canadian Tax Legislation Changes

On March 26, 2026, Bill C-15, an Act to implement certain provisions of the 2025 budget tabled in Parliament on November 4, 2025, was enacted. Bill C-15, among other measures, introduced the Reaccelerated Investment Incentive (“RII”) and the Clean Electricity Investment Tax Credit (“CEITC”). The RII provides enhanced first-year capital cost allowance deductions, while the CEITC is a refundable tax credit of 15 per cent, which is reduced to 5 per cent if prescribed labour requirements are not met, on eligible property, including interprovincial and territorial transmission assets and qualifying refurbishments on eligible property. The enactment of Bill C-15 did not have a material impact on the Company year-to-date in 2026. The Company continues to assess potential future impacts of the legislation.

Cybersecurity Incident

On April 25, 2025, Emera and NSPI discovered a cybersecurity incident involving unauthorized access into certain parts of its Canadian IT network and servers supporting portions of its business applications (the “Cybersecurity Incident”). There was no disruption to the Canadian physical operations or Emera’s US or Caribbean utilities’ operations.

The Company implemented business continuity processes for certain impacted business and administrative functions at its Canadian affiliates. The systematic restoration of affected IT systems and corresponding transition away from business continuity processes is substantially complete. For more information on the impact on internal controls over financial reporting, refer to the “Disclosure and Internal Controls” section. The Company maintains cyber insurance coverage and is working with its insurer on the claims process. At this time, the Cybersecurity Incident is not expected to have a material impact on the Company’s financial position or results of operations. For information on risks associated with cybersecurity incidents generally, refer to the “Enterprise Risk and Risk Management” section in the Company’s 2025 annual MD&A.

Appointments

Executive

Effective November 2, 2026, Chris Smith became President and Chief Executive Officer of NSPI, succeeding Vivek Sood. Most recently, Mr. Smith served as Executive Vice President, Finance and Commercial of NSPI.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

	Three months ended		Nine months ended	
For the		September 30		September 30
millions of USD (except as indicated)	**2026**	2025	**2026**	2025
Operating revenues – regulated electric	**$ 893**	$ 921	**$ 2,557**	$ 2,409
Regulated fuel for generation and purchased power	**$ 220**	$ 204	**$ 615**	$ 553
Contribution to consolidated net income	**$ 217**	$ 220	**$ 537**	$ 522
Contribution to consolidated net income – CAD	**$ 304**	$ 302	**$ 745**	$ 726
Electric sales volumes (Gigawatt hours ("GWh"))	**6,349**	6,270	**16,401**	16,306
Electric production volumes (GWh)	**6,551**	6,589	**17,249**	17,150
Average fuel cost in dollars per megawatt hour ("MWh")	**$ 34**	$ 31	**$ 36**	$ 32

The impact of the change in FX rates increased CAD earnings for the three months ended September 30, 2026, by $5 million, and decreased CAD earnings for the nine months ended September 30, 2026, by $3 million.

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 – 2025	**$ 220**	**$ 522**
Decreased operating revenues quarter-over-quarter due to lower storm cost recovery revenue (offset in OM&G) and unfavourable weather, partially offset by new base rates and customer growth. Year-over-year increased due to new base rates, increased off-system sales, increased regulatory deferral revenue, customer growth, and favourable weather	(28)	148
Increased fuel for generation and purchased power due to higher natural gas prices, higher sales volumes, and a one-time reduction in recoverable fuel and purchased power costs of $10 million USD due to an FPSC-approved settlement agreement	(16)	(62)
Decreased OM&G primarily due to lower storm cost recognition (offset in revenue). Year-over-year also decreased due to lower regulatory deferrals, partially offset by generation outages	60	8
Increased depreciation and amortization due to increased PP&E placed in-service	(6)	(31)
Increased interest expense due to higher debt balances	(2)	(16)
Increased state and municipal taxes quarter-over-quarter due to higher property tax expenses attributable to higher taxable plant values. Year-over-year also impacted by higher revenues.	(4)	(19)
Increased income tax expense primarily due to higher income before provision for income taxes and a valuation allowance recorded for production tax credits to be sold, partially offset by higher benefit from production tax credits	(7)	(6)
Other	-	(7)
Contribution to consolidated net income – 2026	**$ 217**	**$ 537**

Canadian Electric Utilities

For the millions of dollars (except as indicated)	Three months ended September 30 **2026**	2025	Nine months ended September 30 **2026**	2025
Operating revenues – regulated electric	**$ 412**	$ 405	**$ 1,472**	$ 1,440
Regulated fuel for generation and purchased power (1)	**$ 210**	$ 222	**$ 753**	$ 796
Contribution to consolidated net income	**$ 17**	$ 13	**$ 119**	$ 151
Electric sales volumes (GWh)	**2,266**	2,230	**8,199**	7,936
Electric production volumes (GWh)	**2,441**	2,380	**8,774**	8,466
Average fuel costs in dollars per MWh	**$ 86**	$ 93	**$ 86**	$ 94

(1) Regulated fuel for generation and purchased power includes NSPI's FAM on the Condensed Consolidated Statements of Income, however, it is excluded in the segment overview.

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

For the millions of dollars	Three months ended September 30 **2026**	2025	Nine months ended September 30 **2026**	2025
NSPI	**$ 7**	$ 3	**$ 87**	$ 119
Equity investment in NSPML	**10**	10	**32**	32
Contribution to consolidated net income	**$ 17**	$ 13	**$ 119**	$ 151

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 – 2025	**$ 13**	**$ 151**
Increased operating revenues at NSPI quarter-over-quarter due to higher residential sales volumes, favourable weather and changes in electricity pricing effective January 1, 2026 and May 1, 2026, partially offset by lower commercial sales. Increased year-over-year due to higher residential, commercial and industrial sales volumes and favourable weather.	7	32
Decreased regulated fuel for generation and purchased power at NSPI due to lower Nova Scotia output-based pricing system carbon tax, decreased commodity prices, and favourable changes in generation mix, partially offset by increased sales volumes	12	43
Decreased FAM deferral at NSPI primarily due to lower under-recovery of fuel costs	(24)	(81)
Increased OM&G at NSPI due to higher information technology costs, higher net bad debt expense, and lower administrative overhead allocated to PP&E	(5)	(14)
Decreased interest expense, net at NSPI due to the deferral of financing costs associated with the securitization deferral	12	14
Decreased income tax recovery year-over-year as a result of higher clean technology investment tax credits in 2025 at NSPI	1	(18)
Other	1	(8)
Contribution to consolidated net income – 2026	**$ 17**	**$ 119**

Gas Utilities and Infrastructure

On August 12, 2026 Emera completed the sale of NMGC. For further details, refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

For the millions of USD (except as indicated)	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Operating revenues – regulated gas (1)	**$ 224**	$ 227	**$ 912**	$ 908
Operating revenues – non-regulated	**4**	5	**12**	13
Total operating revenue	**$ 228**	$ 232	**$ 924**	$ 921
Regulated cost of natural gas	**$ 37**	$ 39	**$ 193**	$ 245
Contribution to consolidated adjusted net income	**$ 34**	$ 23	**$ 172**	$ 141
Charges related to the sale of NMGC, after-tax (2)	**(3)**	-	**(3)**	-
Contribution to consolidated net income	**$ 31**	$ 23	**$ 169**	$ 141
Contribution to consolidated adjusted net income - CAD	**$ 46**	$ 32	**$ 237**	$ 200
Contribution to consolidated net income – CAD	**$ 42**	$ 32	**$ 233**	$ 200
Gas sales volumes (millions of Therms)	**643**	743	**2,235**	2,359

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2025 – $11 million) for the three months ended September 30, 2026 and $33 million (2025 – $34 million) for the nine months ended September 30, 2026.
(2) Net of income tax recovery of $1 million for the three and nine months ended September 30, 2026.

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

For the millions of USD	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
PGS	**$ 32**	$ 21	**$ 123**	$ 86
NMGC	**(7)**	(6)	**22**	30
Other	**9**	8	**27**	25
Contribution to consolidated adjusted net income	**$ 34**	$ 23	**$ 172**	$ 141

The impact of the change in FX rates was minimal for the three months ended September 30, 2026, and decreased CAD earnings and CAD adjusted net income for the nine months ended September 30, 2026 by $6 million.

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 – 2025	**$ 23**	**$ 141**
Decreased gas revenues quarter-over-quarter due to the sale of NMGC, partially offset by higher rates and off-system sales at PGS. Year-over-year increased due to higher rates and off-system sales at PGS, partially offset by lower fuel revenue at NMGC.	(4)	3
Decreased cost of natural gas due to lower natural gas prices at NMGC, partially offset by higher natural gas prices at PGS	2	52
Decreased OM&G quarter-over-quarter primarily due to lower expenses due to the sale of NMGC. Increased year-over-year due to higher labour and benefit costs at PGS and NMGC, partially offset by lower expenses due to the sale of NMGC	12	(3)
Decreased depreciation quarter-over-quarter due to the sale of NMGC. Year-over-year increased primarily due to PP&E placed in service at PGS	4	(3)
Increased income tax expense primarily due to increased income before provisions for income taxes at PGS	(3)	(11)
Charges related to the sale of NMGC, after-tax	(3)	(3)
Other	-	(7)
Contribution to consolidated net income – 2026	**$ 31**	**$ 169**

Other Electric Utilities

On May 12, 2026, Emera completed the sale of GBPC. For further details, refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

For the millions of USD (except as indicated)	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Operating revenues – regulated electric	**$ 87**	$ 115	**$ 276**	$ 311
Regulated fuel for generation and purchased power	**$ 54**	$ 60	**$ 155**	$ 160
Contribution to consolidated adjusted net income	**$ 7**	$ 11	**$ 17**	$ 20
Loss on sale of GBPC	**(3)**	-	**(15)**	-
Equity securities MTM gain	**(1)**	-	**(1)**	1
Contribution to consolidated net income	**$ 3**	$ 11	**$ 1**	$ 21
Contribution to consolidated adjusted net income – CAD	**$ 11**	$ 16	**$ 24**	$ 28
Contribution to consolidated net income – CAD	**$ 6**	$ 16	**$ 3**	$ 30
Electric sales volumes (GWh)	**278**	349	**875**	977
Electric production volumes (GWh)	**298**	377	**937**	1,045
Average fuel costs in dollars per MWh	**$ 181**	$ 159	**$ 165**	$ 153

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		Nine months ended September 30	
	2026	2025	**2026**	2025
BLPC	**$ 7**	$ 6	**$ 15**	$ 12
GBPC	**1**	6	**2**	9
Other	**(1)**	(1)	**-**	(1)
Contribution to consolidated adjusted net income	**$ 7**	$ 11	**$ 17**	$ 20

The impact of the change in FX rates on CAD earnings for the three and nine months ended September 30, 2026 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 – 2025	**$ 11**	**$ 21**
Decreased operating revenues – regulated electric due to sale of GBPC in Q2 2026, partially offset by higher fuel revenue at BLPC as a result of higher fuel prices	(28)	(35)
Decreased regulated fuel for generation and purchased power due to sale of GBPC in Q2 2026, partially offset by higher fuel revenue at BLPC as a result of higher fuel prices	6	5
Decreased OM&G due to sale of GBPC	10	15
Loss on sale of GBPC	(3)	(15)
Decreased depreciation and amortization due to the sale of GBPC in Q2 2026	6	7
Other	1	3
Contribution to consolidated net income – 2026	**$ 3**	**$ 1**

Other

For the millions of dollars	Three months ended September 30 2026	2025	Nine months ended September 30 2026	2025
Marketing and trading margin (1)(2)	**$ (3)**	$ (3)	**$ 152**	$ 98
Other non-regulated operating revenue	**13**	9	**35**	25
Total operating revenues – non-regulated	**$ 10**	$ 6	**$ 187**	$ 123
Contribution to consolidated adjusted net (loss) income	**$ (118)**	$ (100)	**$ (238)**	$ (227)
Gain (loss) on sale of NMGC, and related charges, after-tax (3)(4)	**12**	-	**12**	(72)
Charges associated with the pending CU Transaction, after-tax (5)	**(5)**	-	**(5)**	-
Loss on sale of GBPC, after tax and transaction costs (6)	**(1)**	-	**(4)**	-
MTM (loss) gain, after-tax (7)	**(75)**	(35)	**(16)**	138
Contribution to consolidated net (loss) income	**$** (187)	$ (135)	**$** (251)	$ (161)

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax MTM loss of $113 million for the three months ended September 30, 2026 (2025 – $37 million loss) and a loss of $6 million for the nine months ended September 30, 2026 (2025 – $160 million gain).
(3) Net of income tax expense of $23 million for the three and nine months ended September 30, 2026.
(4) Includes an impairment charge of $75 million ($71 million after-tax) and transaction costs of $2 million ($1 million after-tax) for the nine months ended September 30, 2025.
(5) Net of income tax recovery of $2 million for the three and nine months ended September 30, 2026.
(6) Net of income tax expense of $1 million for the three months ended September 30, 2026 and $1 million income tax recovery for the nine months ended September 30, 2026.
(7) Net of income tax recovery of $30 million for the three months ended September 30, 2026 (2025 – $15 million recovery) and $6 million income tax expense for the nine months ended September 30, 2026 (2025 – $56 million expense).

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

For the millions of dollars	Three months ended September 30 2026	2025	Nine months ended September 30 2026	2025
Emera Energy				
EES	**$ (3)**	$ (8)	**$ 78**	$ 47
Other	**1**	(1)	**12**	(5)
Corporate – see breakdown of contribution below	**(116)**	(96)	**(328)**	(274)
Other	**-**	5	**-**	5
Contribution to consolidated adjusted net (loss) income	**$ (118)**	$ (100)	**$ (238)**	$ (227)

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 (loss) income – 2025	**$ (135)**	**$ (161)**
Increased marketing and trading margin year-over-year due to favourable weather conditions in Q1 that led to higher natural gas prices and increased volatility that created profitable opportunities	-	54
Increased OM&G at Corporate quarter-over-quarter primarily due to a loss on the incentive hedge and increased costs as a result of the NYSE listing. Year-over-year primarily due to a lower gain on the incentive hedge and increased costs as a result of the NYSE listing	(17)	(30)
Increased equity earnings at Bear Swamp year-over-year due to business interruption insurance received related to an unplanned outage in 2025 and higher generation	1	24
Increased Corporate FX gain on the translation of USD short-term debt balances	4	-
Increased interest expense due to higher long-term debt resulting from the timing of financings, partially offset by interest earned on debt proceeds held in invested cash. Year-over-year is also partially offset by lower short-term debt	(3)	(31)
Decreased income tax recovery year-over-year due to decreased loss before provision for income taxes, an unfavourable deferred income tax asset valuation allowance adjustment and an unfavourable impact of foreign currency translation	(2)	(17)
Charges associated with the pending CU Transaction, after-tax	(5)	(5)
Unfavourable changes in MTM, after-tax, quarter-over-quarter, due to amortization of gas transportation assets and changes in existing positions at EES. Unfavourable change in MTM, after-tax, year-over-year due to amortization of gas transportation assets, partially offset by changes in existing positions at EES	(40)	(154)
Gain on sale of NMGC and related charges, after-tax. Year-over-year also due to the impairment charge taken in Q2 2025.	12	84
Other	(2)	(15)
Contribution to consolidated net (loss) income – 2026	**$ (187)**	**$ (251)**

Corporate

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

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Operating expenses (1)	**$ (32)**	$ (16)	**$ (73)**	$ (43)
Interest expense	**(96)**	(93)	**(311)**	(280)
Income tax recovery	**36**	38	**119**	112
Preferred dividends	**(21)**	(19)	**(60)**	(56)
Other (2)(3)	**(3)**	(6)	**(3)**	(7)
Corporate adjusted net loss (4)(5)(6)	**$ (116)**	$ (96)	**$ (328)**	$ (274)

(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 $3 million ($2 million after-tax) for the three months ended September 30, 2026 (2025 – $2 million net loss, pre-tax and $2 million loss, after-tax) and a $4 million net loss, pre-tax ($3 million after-tax) for the nine months ended September 30, 2026 (2025 – $12 million net loss, pre-tax and $9 million loss, after-tax) on FX hedges, as discussed above.

(4) Excludes a MTM gain, after-tax, of $1 million for the three months ended September 30, 2026 (2025 – $10 million loss, after-tax) and a MTM loss, after-tax of $15 million for the nine months ended September 30, 2026 (2025 – $23 million gain, after-tax).

(5) Excludes a gain on sale and transaction charges related to the sale of NMGC of $12 million ($8 million after-tax) for the three and nine months ended September 30, 2026. (2025 – $75 million ($71 million after-tax) impairment charge and $2 million ($1 million after-tax) in transaction costs).

(6) Excludes a $1 million tax expense related to the loss on the sale of GBPC for the three months ended September 30, 2026, and a $5 million loss on sale of GBPC ($4 million after-tax) for the nine months ended September 30, 2026.

LIQUIDITY AND CAPITAL RESOURCES

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

Emera’s future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has an approximate $21.5 billion capital investment plan over the 2027 through 2031 period to support ongoing growth. Capital investments at Emera’s regulated utilities are subject to regulatory approval.

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

Emera has total committed credit facilities with varying maturities that cumulatively provide $3.1 billion CAD and $1.9 billion USD of credit, with approximately $1.5 billion CAD and $870 million USD undrawn and available at September 30, 2026. The Company was holding a cash balance of $600 million at September 30, 2026. For further discussion, refer to the “Debt Management” section below.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2026 and 2025 include:

millions of dollars		**2026**		2025		Change
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, beginning of period	**$**	**371**	$	221	$	150
Provided by (used in):						
Operating cash flow before changes in working capital		**2,113**		1,972		141
Changes in non-cash working capital		**315**		(382)		697
Operating activities	**$**	**2,428**	$	1,590	$	838
Investing activities		**(1,595)**		(2,518)		923
Financing activities		**(573)**		941		(1,514)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**76**		(5)		81
Cash, cash equivalents, and restricted cash, end of period	**$**	**707**	$	229	$	478

Cash Flow from Operating Activities

Net cash provided by operating activities increased $838 million to $2,428 million for the nine months ended September 30, 2026, compared to $1,590 million for the same period in 2025.

Cash from operations before changes in working capital increased $141 million year-over-year. This increase was due to fuel and capacity clauses over-recoveries at TEC, and higher marketing and trading margin at EES. These were partially offset by higher Corporate costs, impact of sale and purchased gas adjustment refund to customers at NMGC, and increased OM&G and lower current income tax recovery at NSPI as a result of higher clean energy technology investment tax credits in 2025.

Changes in non-cash working capital increased operating cash flow by $697 million year-over-year. This increase was due to favourable changes in accounts payable at TEC due to timing of storm invoice payments, timing of settlements and favourable changes in posted margin at EES, and favourable changes in accounts receivable at NSPI. These were partially offset by unfavourable changes in accounts payable due to timing and unfavourable changes in fuel inventory due to increased purchases at NSPI, and unfavourable changes in accounts receivable at PGS due to new base rates.

Cash Flow from Investing Activities

Net cash used in investing activities decreased $923 million to $1,595 million for the nine months ended September 30, 2026, compared to $2,518 million for the same period in 2025. The decrease was due to proceeds from sale of NMGC and GBPC, partially offset by higher capital investment.

Capital investments, including AFUDC, for the nine months ended September 30, 2026, were $2,787 million, compared to $2,615 million for the same period in 2025. Details of the 2026 capital investment by segment are shown below:

- $1,762 million – Florida Electric Utility (2025 – $1,616 million);
- $504 million – Gas Utilities and Infrastructure (2025 – $444 million);
- $465 million – Canadian Electric Utilities (2025 – $491 million);
- $52 million – Other Electric Utilities (2025 – $63 million); and
- $4 million – Other (2025 – $1 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $1,514 million to $573 million for the nine months ended September 30, 2026, compared to net cash provided by financing activities of $941 million for the same period in 2025. This increase was due to the retirement of long-term debt and higher net repayments of credit facilities at Corporate, lower issuances of long-term debt at TEC and lower net proceeds from committed facilities and short-term debt at NSPI. These were partially offset by higher proceeds from Corporate long-term debt and short-term debt, higher net issuances of long-term debt at NSPI, higher net borrowing on committed credit facilities at TEC, higher proceeds from long-term debt at PGS, and higher issuance of common shares.

Contractual Obligations

As at September 30, 2026, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Long-term debt principal (1)	$ 14	$ 67	$ 724	$ 1,404	$ 512	$ 16,612	$ 19,333
Interest payment obligations (2)	373	960	943	876	841	11,868	15,861
Purchased power (3)	79	429	410	461	454	6,491	8,324
Transportation (4)	397	818	547	463	387	3,060	5,672
Fuel, gas supply and storage	146	388	186	162	43	64	989
Capital projects	171	111	42	2	7	-	333
Pension and post-retirement obligations (5)	7	28	28	28	24	240	355
Asset retirement obligations	4	1	2	1	1	758	767
Other	48	98	189	64	54	381	834
	$ 1,239	$ 2,900	$ 3,071	$ 3,461	$ 2,323	$ 39,474	$ 52,468

(1) The Company has hybrid notes that mature in 2054 and 2056. These maturity dates have been used in the computation of the Company's long-term debt principal and interest payment obligations at September 30, 2026. The Company has the option to repay such notes in advance of maturity upon exercise of the Company's redemption rights in accordance with terms of the applicable indenture.
(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at September 30, 2026, including any expected required payment under associated swap agreements.
(3) Annual requirement to purchase electricity from Independent Power Producers or other utilities over varying contract lengths.
(4) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $118 million related to a gas transportation contract between PGS and SeaCoast through 2040, and $38 million of future performance obligations related to asset management agreements between PGS and EES through 2030.
(5) Includes the estimated contractual obligation, which is calculated as the current legislatively required contributions to the registered funded pension plans, plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. On May 11, 2026, the NSEB issued its decision on NSPML's 2026 assessment application, approving the collection of up to $198 million from NSPI for recovery of costs associated with the Maritime Link in 2026. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to NSEB approval.

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

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to unsecured committed syndicated revolving and non-revolving bank lines of credit in either CAD or USD, per the table below as at September 30, 2026.

millions of dollars in currency as noted below	Maturity	Credit Facilities	Utilized	Undrawn and Available
In CAD:				
Emera – committed revolving credit facility	June 2031	$ 1,300	$ 162	$ 1,138
NSPI – committed revolving credit facility	June 2031	800	420	380
NSPI – non-revolving facility	May 2027	500	500	-
Emera – non-revolving facility	June 2027	500	500	-
In USD:				
TEC – committed revolving credit facility	November 2030	1,200	886	314
TECO Finance – committed revolving credit facility	November 2030	400	-	400
PGS – committed revolving facility	November 2030	250	102	148
Other – committed revolving credit facilities	Various	8	-	8

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, 2026.

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

Canadian Electric Utilities

On July 14, 2026, the holders of NSPI's $40 million senior unsecured notes exercised their option to extend the maturity date from August 14, 2026, to August 14, 2056.

On June 19, 2026, NSPI amended its $800 million revolving credit facility to extend the maturity date from June 24, 2029, to June 19, 2031. There were no other material changes in commitment amount, maturity, or interest from the prior agreement.

On May 1, 2026, NSPI amended its $500 million non-revolving facility to extend the maturity date from May 21, 2026, to May 21, 2027. There were no other material changes in commercial terms from the prior agreement.

On April 17, 2026, NSPI issued $300 million in unsecured notes that bear interest at 3.95 per cent with a maturity date of April 17, 2031. Proceeds from this issuance have been used for general corporate purposes, including repayment of existing debt.

Gas Utilities and Infrastructure

On May 5, 2026, PGS executed an agreement to issue $200 million USD in senior notes. The agreement included $50 million USD senior notes (“Series A”) that bear interest at 4.91 per cent with a maturity date of May 5, 2031, $100 million USD senior notes (“Series B”) that bear interest at 5.39 per cent with a maturity date of May 5, 2036, and $50 million USD senior notes (“Series C”) that bear interest at 5.64 per cent with a maturity date of August 20, 2041. Proceeds from Series A and Series B were received on May 5, 2026, and were used for the repayment of short-term debt outstanding. Proceeds from Series C were received on August 20, 2026, and were used for general corporate purposes, including repayment of existing debt.

Other Electric Utilities

On March 18, 2026, BLPC amended its $10 million USD note to extend the maturity date from March 2026 to May 2031, reduced the interest rate from 2.05 per cent to 1.90 per cent, and change the principal payment from $0.25 million USD quarterly to $0.5 million USD semi-annually.

On February 9, 2026, BLPC entered into a $46 million USD non-revolving facility which matures in 2031 and bears interest at 1.80 per cent. As of September 30, 2026, BLPC has drawn $44 million USD on the facility.

Other

At September 30, 2026, the Company had $97 million of cash held in trust, recorded in “Restricted Cash” on the Condensed Consolidated Balance Sheets, related to debt interest payments due on October 1, 2026. The funds had been transferred to the applicable paying agent in accordance with the underlying debt agreements but were not settled to bondholders until October 1, 2026. The transaction settled in the ordinary course of business and did not impact the Company's liquidity, cash flows, or debt obligations.

On June 19, 2026, Emera amended its $1.3 billion revolving credit facility to extend the maturity date from June 24, 2029, to June 19, 2031. There were no other material changes in commercial terms from the prior agreement.

On June 4, 2026, Emera entered into a $500 million non-revolving facility which matures on June 4, 2027. The credit agreement contains customary representations and warranties, events of default and financial and other covenants. The non-revolving facility’s interest rates are referenced to the Term CORRA or prime rate, plus a margin. Proceeds from this facility were used for repayment of existing debt and general corporate purposes.

On March 4, 2026, EUSHI Finance Inc. (“EUSHI Finance”), Emera Finance, Emera US Holdings Inc. (“EUSHI”) and Emera filed a new shelf registration statement on Form F-10 and Form F-3 (“Registration Statement”), with the Nova Scotia Securities Commission (“NSSC”) and the US Securities and Exchange Commission (“SEC”) under the US/Canada Multijurisdictional Disclosure System. The Registration Statement was filed in connection with the prospective offer and issue by EUSHI Finance or Emera Finance of one or more series of senior and/or subordinated unsecured debt securities (“Debt Securities”), in an aggregate principal amount of up to $2.25 billion USD, during the 25-month period that the short form base shelf prospectus contained in the Registration Statement (“Base Shelf Prospectus”), including any further amendments thereto, remains valid. The Debt Securities may be offered in one or more transactions, at prices, with maturities and on terms to be set forth in one or more prospectus supplements to be filed with the NSSC and the SEC at the time of any such offering.

On March 23, 2026, Emera Finance completed an issuance of $750 million USD aggregate principal amount of fixed-to-fixed reset rate junior subordinated notes, pursuant to the prospectus supplement, dated March 23, 2026, to the Base Shelf Prospectus. The issuance consisted of $375 million USD aggregate principal amount of 6.65 per cent Series A fixed-to-fixed reset rate junior subordinated notes due 2056 and $375 million USD aggregate principal amount of 6.85 per cent Series B fixed-to-fixed reset rate junior subordinated notes due 2056 (collectively, the “Notes”). The Notes are fully and unconditionally guaranteed, on a joint, several and subordinated basis, by Emera and EUSHI.

On March 27, 2026, Emera Finance completed an issuance of $750 million USD aggregate principal amount of senior notes pursuant to the prospectus supplement, dated March 27, 2026, to the Base Shelf Prospectus. The issuance consisted of $450 million USD aggregate principal amount of senior notes that bear interest at a rate of 4.50 per cent with a maturity date of April 1, 2029 and $300 million USD aggregate principal amount of senior notes that bear interest at a rate of 5.20 per cent with a maturity date of April 1, 2033. The senior notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera and EUSHI.

Together these issuances were used to redeem all $1.2 billion USD of Emera's outstanding 6.75 per cent fixed-to-floating subordinated notes - Series 2016-A due 2076, and to repay Emera US Finance’s $750 million USD 3.55 per cent senior unsecured note on June 15, 2026, upon maturity.

On February 20, 2026, Emera amended its $200 million unsecured non-revolving facility to extend the maturity date from February 20, 2026 to February 19, 2027. There were no other material changes to the terms from the prior agreement. This facility was subsequently repaid on August 20, 2026.

Credit Ratings

Emera’s credit ratings are consistent with those disclosed in the Company’s 2025 annual MD&A, with material updates noted below:

On May 20, 2026, Moody's Ratings revised its outlook on Emera and TEC to stable from negative with no changes to existing ratings.

Guarantees and Letters of Credit

Emera’s guarantees and letters of credit are consistent with those disclosed in the Company’s 2025 annual MD&A, with material updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $93 million USD (December 31, 2025 – $271 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually, as required.

Emera, on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2027. The amount committed as at September 30, 2026 was $72 million (December 31, 2025 – $70 million).

Emera’s guarantee of $66 million USD relating to outstanding notes of ECI was automatically terminated in Q2 2026, and no obligations remain outstanding.

Outstanding Stock Data

Common Stock

Issued and outstanding:	millions of shares		millions of dollars
Balance, December 31, 2025	301.76	$	9,387
Issuance of common stock under ATM program (1)	2.66		183
Issued under the DRIP, net of discounts	3.09		213
Senior management stock options exercised and Employee Share Purchase Plan	0.73		44
Balance, September 30, 2026	**308.24**	**$**	**9,827**

(1) For the three months ended September 30, 2026, no common shares were issued under Emera's ATM program. For the nine months ended September 30, 2026, a total of 2,657,496 common shares were issued under Emera's ATM program at an average price of $69.89 per share for gross proceeds of $186 million ($183 million, net of after-tax issuance costs). As at September 30, 2026, an aggregate gross sales limit of $414 million remained available for issuance under the ATM program.

As at November 4, 2026, the amount of issued and outstanding common shares was 308.3 million.

If all outstanding stock options were converted as at November 4, 2026, an additional 4.3 million common shares would be issued and outstanding.

Preferred Stock

As at November 4, 2026, Emera had the following preferred shares issued and outstanding: Series A – 6.0 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 April 9, 2026, Emera announced that it would not redeem the currently outstanding Cumulative Minimum Rate Reset First Preferred Shares, Series J (“Series J Shares”) on May 15, 2026 (the “Conversion Date”).

On April 15, 2026, Emera announced a dividend rate of 6.345 per cent per annum on the Series J Shares during the five-year period commencing on May 15, 2026, and ending on (and inclusive of) May 14, 2031. Emera also announced a dividend rate of 5.598 per cent on the Cumulative Floating Rate First Series K Shares (“Series K Shares”) for the three-month period commencing on May 15, 2026, and ending on (inclusive of) August 14, 2026.

During the conversion period between April 15, 2026, and April 30, 2026, the holders of Series J Shares had the right, at their option, to convert all or any of their Series J Shares, on a one-for-one basis, into Series K Shares. On May 5, 2026, Emera announced that after having taken into account all conversion notices received from holders of its outstanding Series J Shares by the April 30, 2026 deadline for conversion notices, less than the 1,000,000 Series J Shares required to give effect to conversions into Series K Shares were tendered for conversion. As a result, in accordance with certain rights, privileges, restrictions and conditions attaching to the Series J Shares, none of Emera’s outstanding Series J Shares were converted into Series K Shares on May 15, 2026. On the Conversion Date there was 8.0 million Series J Shares outstanding.

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 $39 million for the three months ended September 30, 2026 (2025 – $49 million) and $139 million for the nine months ended September 30, 2026 (2025 – $140 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 "Contractual Obligations" section.

- 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, 2026 (2025 – $1 million) and $12 million for the nine months ended September 30, 2026 (2025 – $12 million).

As at September 30, 2026, Emera and its associated companies had $53 million due from related parties (December 31, 2025 – $35 million) recorded in "Receivables and other current assets", and $46 million due to related parties (December 31, 2025 – $32 million) recorded in "Other Current Liabilities", on the Condensed Consolidated Balance Sheets.

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 2025 annual MD&A, except the material update below.

Completion of the Pending CU Transaction Risks

The CU Transaction is subject to Emera shareholder approval, approval by ATCO and CU securityholders and certain court, stock exchange and regulatory approvals, including approval of the Court of King's Bench of Alberta, the Alberta Utilities Commission, the U.S. Federal Communications Commission, the Committee on Foreign Investment in the United States, the U.S. Federal Energy Regulatory Commission, the Comisión Nacional Antimonopolio of Mexico, the Toronto Stock Exchange and the New York Stock Exchange, and approvals or notifications under the Competition Act (Canada), the Canada Transportation Act, the Australian Foreign Acquisitions and Takeovers Act 1975, the Australian Competition and Consumer Act 2010 and the United States Hart-Scott-Rodino Antitrust Improvements Act of 1976, and the satisfaction of closing conditions. On October 22, 2026, the Northwest Territories Public Utilities Board confirmed that no approval under the Northwest Territories *Public Utilities Act* is required to effect the CU Transaction.

Failure to obtain the required approvals or satisfy or waive the conditions contained in the arrangement agreement may result in the termination of the arrangement agreement. There is no assurance that such required approvals and closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Emera will complete the CU Transaction in the timeframe or on the basis described herein, if at all. The termination of the arrangement agreement may have a negative effect on the common shares of the Company. If the closing of the CU Transaction does not take place as contemplated, the Company could suffer a material adverse effect.

A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Company's ability to complete the CU Transaction and on the Company's business, financial condition or results of operations. In addition, in the event that such regulatory agencies impose unfavourable terms and/or conditions on Emera or any acquired utility (including the requirement to sell or divest certain assets or limitations on the future conduct of the individual or combined entities), the Company may still be required to complete the transaction on the terms set forth in the arrangement agreement.

ATCO and CU are public companies, and their directors owe fiduciary duties to ATCO and CU shareholders, respectively (and other stakeholders) which may require them to consider competing offers to purchase the securities or assets of ATCO or CU as alternatives to the CU Transaction. The arrangement agreement preserves the ability of the directors of ATCO or CU to consider an alternative or competing offer in certain circumstances if such offer constitutes a superior proposal and to change or withdraw their recommendations in respect of the CU Transaction or to enter into an agreement with respect to the superior proposal that is conditional on the failure of the ATCO or CU shareholders approving the CU Transaction (although ATCO and CU do not have a right to terminate the arrangement agreement due to a superior proposal). If a superior proposal to acquire ATCO and CU is made, Emera will have the right during a matching period to offer to amend the terms of the arrangement agreement, and ATCO and CU and their representatives are required to negotiate in good faith with Emera regarding any revisions to the arrangement agreement, which could result in changes to terms and conditions of the CU Transaction.

Emera expects the pending CU Transaction will provide benefits to the Company, including that the acquisition will be accretive to Emera's adjusted EPS in the first full year following its completion. However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize or may not occur within the time periods currently anticipated by the Company. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Company. The challenge of combining previously independent businesses makes evaluating the Company's business and future financial prospects difficult. The past financial performance of the Company may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the acquisition may include terms which could have a material adverse effect on the Company's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the CU Transaction may adversely affect the financial performance of the Company, the price of its common shares and the ability of Emera to continue to pay dividends on its common shares at current levels or at all. The declaration of dividends by the Company is at the discretion of the Board of Directors.

Each of the parties to the arrangement agreement has the right to terminate the arrangement agreement in certain circumstances. There is no certainty, nor can the Company provide any assurance, that the arrangement agreement will not be terminated before the completion of the CU Transaction. For instance, the Company has the right, in certain circumstances, to terminate the arrangement agreement if there is a material adverse effect as defined in the arrangement agreement in respect of ATCO or CU. Conversely, ATCO and CU have the right, in certain circumstances, to terminate the arrangement agreement if there is a material adverse effect as defined in the arrangement agreement in respect of the Company. There is no assurance that a material adverse effect under the arrangement agreement will not occur before the effective date of the CU Transaction, in which case the Company, ATCO or CU could elect to terminate the arrangement agreement and the CU Transaction would not proceed.

In addition to the potential liability for damages for breach of the arrangement agreement by Emera, if the arrangement agreement is terminated in certain circumstances, Emera may be obligated to pay to CU (on behalf of CU and ATCO) a termination fee of $634 million or a reverse regulatory termination fee of $720 million in cash.

Emera expects to incur significant costs associated with completing the CU Transaction. The majority of these costs will be non-recurring expenses and will consist of transaction costs, including costs of obtaining regulatory approvals, and must be paid by the Company even if the CU Transaction is not completed. Additional unanticipated costs may also be incurred relating to the CU Transaction. If the CU Transaction is not completed, there will be no benefit to the Company's shareholders associated with these costs.

The arrangement agreement restricts the Company from taking specified actions (without the consent of ATCO and CUL) until the CU Transaction is completed, which may adversely affect the ability of the Company to execute certain business strategies, including, but not limited to, the ability in certain cases to enter into or amend contracts, acquire or dispose of assets, incur indebtedness or incur capital expenditures. These restrictions may prevent the Company from pursuing attractive business opportunities that may arise prior to the completion of the CU Transaction.

The pendency of the CU Transaction could cause the attention of the Company's management to be diverted from day-to-day operations. These disruptions could be exacerbated by a delay in the completion of the CU Transaction and could have an adverse effect on the business, operating results or prospects of the Company regardless of whether the CU Transaction is ultimately completed.

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars	**September 30 2026**	December 31 2025
Regulatory Deferral:		
Derivative instrument assets (1)	**$ 46**	$ 24
Derivative instrument liabilities (2)	**(16)**	(34)
Regulatory assets (1)	**17**	36
Regulatory liabilities (2)	**(47)**	(25)
Net asset	**$ -**	$ 1
HFT Derivatives:		
Derivative instrument assets (1)	**$ 180**	$ 158
Derivative instrument liabilities (2)	**(1,178)**	(614)
Net liability	**$ (998)**	$ (456)
Other Derivatives:		
Derivative instrument assets (1)	**$ 9**	$ 16
Derivative instrument liabilities (2)	**(16)**	(1)
Net asset (liability)	**$ (7)**	$ 15

(1) Current and other assets.

(2) Current and long-term liabilities.

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$ (3)**	$ (6)	**$ 1**	$ (12)
HFT Derivatives:				
Non-regulated operating revenues	**$ (469)**	$ 16	**$ (89)**	$ 480
Other Derivatives:				
OM&G	**$ (23)**	$ 11	**$ 1**	$ 36
Other (expense) income, net	**2**	(16)	**(21)**	21
Net gains (losses)	**$ (21)**	$ (5)	**$ (20)**	$ 57
Total net gains (losses)	**$ (493)**	$ 5	**$ (108)**	$ 525

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

As of September 30, 2026, the unrealized gain in Accumulated Other Comprehensive Income ("AOCI") was $9 million, after-tax (December 31, 2025 – $10 million, after-tax). For the three and nine months ended September 30, 2026, unrealized gains of nil (2025 – $1 million) and $1 million (2025 – $2 million) respectively were reclassified from AOCI into interest expense, net.

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as required by Canadian and US Securities laws. The Company's internal control framework is based on criteria published in the Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, designed the Company's DC&P and ICFR as at September 30, 2026, 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.

In April 2025, the Company experienced a Cybersecurity Incident that impacted certain financial systems and processes at its Canadian affiliates. As a result, the Company transitioned these to business continuity processes and implemented additional ICFR during this period. Since that time, the Company completed the restoration of substantially all the financial systems and transitioned back from corresponding business continuity processes. For more information on the Cybersecurity Incident, refer to the "Other Developments" section.

There were no changes in the Company's ICFR during the quarter ended September 30, 2026, that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

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 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 2025 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

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

Accounting for Environmental Credits and Environmental Credit Obligations

In May 2026, the FASB issued ASU 2026-02, Environmental Credits and Environmental Credit Obligations (Topic 818). This ASU establishes new guidance for the recognition, measurement, presentation, and disclosure of environmental credits (such as renewable energy credits, carbon offsets, and similar instruments) and environmental credit obligations. The ASU is effective for fiscal years beginning after December 15, 2027, and interim periods within those fiscal years. Early adoption is permitted. An entity must apply the guidance retrospectively through a cumulative-effect adjustment to retained earnings. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements.

Accounting for Government Grants Received by Business Entities

In December 2025, the FASB issued ASU 2025-10, Government Grants (Topic 832) – Accounting for Government Grants Received by Business Entities. The ASU adds guidance to ASC 832 on the recognition, measurement, and presentation of government grants. The guidance will be effective for annual reporting periods beginning after December 15, 2028, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The standard updates are to be applied using either a modified prospective, modified retrospective, or full retrospective approach, as detailed in the ASU. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements.

Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, the FASB issued ASU 2025-06, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software. The standard update modernizes accounting for internal-use software by eliminating references to project stages and clarifying the threshold to begin capitalizing costs. The standard update also specifies that the disclosure requirements under ASC 360, Property, Plant and Equipment, apply to capitalized software costs accounted under ASC 350-40. The guidance will be effective for annual reporting periods beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The standard updates are to be applied using either a prospective, retrospective, or modified transition approach. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements.

Disaggregation of Income Statement Expenses

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

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q3 2026**	Q2 2026	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024
Operating revenues	**$ 1,984**	$ 2,011	$ 2,813	$ 2,006	$ 2,106	$ 1,988	$ 2,676	$ 1,763
Net income attributable to common shareholders	**$ 182**	$ 105	$ 562	$ 68	$ 228	$ 135	$ 583	$ 154
EPS – basic	**$ 0.59**	$ 0.34	$ 1.85	$ 0.23	$ 0.76	$ 0.45	$ 1.96	$ 0.52
EPS – diluted	**$ 0.59**	$ 0.34	$ 1.85	$ 0.25	$ 0.76	$ 0.45	$ 1.96	$ 0.52

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

Q3 2026 compared to Q3 2025

For explanation of variances, refer to the "Consolidated Income Statement Highlights" section.

Q2 2026 compared to Q2 2025

For Q2 2026 net income attributable to common shareholders, compared to Q2 2025, decreased by $30 million due to increased MTM losses, increased Corporate costs, decreased earnings at NMGC and EES and lower earnings due to loss on sale of GBPC, after tax and transaction costs. These were partially offset by increased earnings at PGS and higher equity earnings at Bear Swamp. The change in EPS was also impacted by an increase in weighted average shares outstanding.

Q1 2026 compared to Q1 2025

For Q1 2026 net income attributable to common shareholders, compared to Q1 2025, decreased by $21 million due to decreased MTM gains, decreased earnings at NSPI, the impact of a stronger CAD and increased Corporate costs. These were partially offset by increased earnings at EES, PGS and TEC. The change in EPS was also impacted by an increase in weighted average shares outstanding.

Q4 2025 compared to Q4 2024

For Q4 2025, net income attributable to common shareholders, compared to Q4 2024, decreased $86 million due to decreased earnings at NSPI and NMGC; increased Corporate costs; and Q4 2024 tax benefit related to a specific financing structure and its wind-up and the tax benefit related to the incremental gain on sale of Emera's interest in the Labrador Island Link. These were partially offset by decreased MTM losses; increased earnings at EES; and Q4 2024 charges related to wind-down costs for certain asset impairments. The change in EPS was also impacted by an increase in weighted average shares outstanding.