EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2026 and 2025

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2026	2025	**2026**	2025
Operating revenues				
Regulated electric	**$ 1,782**	$ 1,829	**$ 5,391**	$ 5,227
Regulated gas	**307**	308	**1,244**	1,264
Non-regulated	**(105)**	(31)	**173**	279
Total operating revenues (note 5)	**1,984**	2,106	**6,808**	6,770
Operating expenses				
Regulated fuel for generation and purchased power	**578**	547	**1,759**	1,653
Regulated cost of natural gas	**52**	53	**266**	346
Operating, maintenance and general expenses ("OM&G")	**498**	578	**1,692**	1,673
Provincial, state and municipal taxes	**132**	124	**395**	364
Depreciation and amortization	**321**	324	**996**	959
Impairment charge (note 3)	**-**	-	**-**	75
Total operating expenses	**1,581**	1,626	**5,108**	5,070
Income from operations	**403**	480	**1,700**	1,700
Income from equity investments (note 7)	**20**	15	**73**	48
Other income, net (note 8)	**57**	19	**63**	135
Interest expense, net	**250**	260	**796**	764
Income before provision for income taxes	**230**	254	**1,040**	1,119
Income tax expense (note 9)	**27**	6	**131**	116
Net income	**203**	248	**909**	1,003
Non-controlling interest in subsidiaries ("NCI")	**-**	1	**-**	1
Preferred stock dividends	**21**	19	**60**	56
Net income attributable to common shareholders	**$ 182**	$ 228	**$ 849**	$ 946
Weighted average shares of common stock outstanding (in millions) (note 11)				
Basic	**307.7**	299.9	**305.8**	298.5
Diluted	**308.6**	300.6	**306.8**	299.0
Earnings per common share (note 11)				
Basic	**$ 0.59**	$ 0.76	**$ 2.78**	$ 3.17
Diluted	**$ 0.59**	$ 0.76	**$ 2.77**	$ 3.16
Dividends per common share declared	**$ 0.7325**	$ 0.7250	**$ 2.1975**	$ 2.1750

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

Emera Incorporated
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of dollars	Three months ended September 30 2026	Three months ended September 30 2025	Nine months ended September 30 2026	Nine months ended September 30 2025
Net income	**$ 203**	$ 248	**$ 909**	$ 1,003
Other comprehensive income (loss) ("OCI"), net of tax				
Foreign currency translation adjustment (1)	**(22)**	257	**441**	(428)
Unrealized (losses) gains on net investment hedges (2)	**(22)**	(33)	**(71)**	56
Cash flow hedges – net of reclassification adjustment for gains included in income	**-**	(1)	**(1)**	(2)
Unrealized gains (losses) on available-for-sale investment	**-**	1	**(1)**	1
Net change in unrecognized pension and post-retirement benefit obligation (3)	**(4)**	1	**(9)**	(3)
OCI (4)	**$ (48)**	$ 225	**$ 359**	$ (376)
Comprehensive income	**155**	473	**1,268**	627
Comprehensive income attributable to NCI	**-**	1	**-**	1
Comprehensive income of Emera Incorporated	**$ 155**	$ 472	**$ 1,268**	$ 626

(1) Net of tax expense of $1 million (2025 – $3 million expense) for the three months ended September 30, 2026 and tax expense of $3 million (2025 – $6 million recovery) for the nine months ended September 30, 2026.
(2) As of September 30, 2026, the Company had $1.5 billion United States dollar ("USD") denominated debt (2025 – $1.2 billion USD hybrid notes) designated as a hedge of the foreign currency exposure of its net investment in USD denominated operations. Refer to note 14.
(3) Net of tax recovery of $2 million (2025 – nil) for the three and nine months ended September 30, 2026.
(4) Net of tax recovery of $1 million (2025 – $3 million expense) for the three months ended September 30, 2026 and tax expense of $1 million (2025 – $6 million recovery) for the nine months ended September 30, 2026.

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

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of dollars	**September 30 2026**	December 31 2025
Assets		
Current assets		
Cash and cash equivalents	**$ 600**	$ 349
Restricted cash	**107**	16
Inventory	**859**	821
Derivative instruments (notes 13 and 14)	**196**	156
Regulatory assets (note 6)	**237**	409
Receivables and other current assets (note 16)	**2,472**	2,439
Assets held for sale (note 3)	**-**	199
	4,471	4,389
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $11,388 and $10,845, respectively	**29,582**	27,408
Other assets		
Deferred income taxes (note 9)	**436**	421
Derivative instruments (notes 13 and 14)	**39**	42
Regulatory assets (note 6)	**2,910**	2,789
Net investment in direct finance and sales type leases	**555**	572
Investments subject to significant influence (note 7)	**634**	634
Goodwill	**5,776**	5,580
Other long-term assets (note 23)	**1,223**	894
Assets held for sale (note 3)	**-**	2,088
	11,573	13,020
Total assets	**$ 45,626**	$ 44,817

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

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited) – Continued

As at millions of dollars	**September 30 2026**	December 31 2025
Liabilities and Equity		
Current liabilities		
Short-term debt (note 18)	**$ 2,415**	$ 1,807
Current portion of long-term debt (note 19)	**44**	1,201
Accounts payable	**1,766**	1,948
Derivative instruments (notes 13 and 14)	**823**	534
Regulatory liabilities (note 6)	**245**	211
Other current liabilities	**804**	535
Liabilities associated with assets held for sale (note 3)	**-**	391
	6,097	6,627
Long-term liabilities		
Long-term debt (note 19)	**19,126**	18,453
Deferred income taxes (note 9)	**2,776**	2,516
Derivative instruments (notes 13 and 14)	**387**	115
Regulatory liabilities (note 6)	**1,582**	1,458
Pension and post-retirement liabilities	**266**	268
Other long-term liabilities	**1,031**	960
Liabilities associated with assets held for sale (note 3)	**-**	1,024
	25,168	24,794
Equity		
Common stock (note 10)	**9,827**	9,387
Cumulative preferred stock (note 21)	**1,422**	1,422
Contributed surplus	**88**	86
Accumulated other comprehensive income ("AOCI") (note 12)	**1,232**	873
Retained earnings	**1,792**	1,614
Total Emera Incorporated equity	**14,361**	13,382
Non-controlling interest in subsidiaries ("NCI")	**-**	14
Total equity	**14,361**	13,396
Total liabilities and equity	**$ 45,626**	$ 44,817

Commitments and contingencies (note 20)

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

Approved on behalf of the Board of Directors

"Karen Sheriff"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of dollars	Nine months ended September 30 2026	2025
Operating activities		
Net income	**$ 909**	$ 1,003
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,001**	963
Income from equity investments, net of dividends	**(7)**	5
Allowance for funds used during construction ("AFUDC") – equity	**(39)**	(49)
Deferred income taxes, net	**99**	119
Net change in pension and post-retirement liabilities	**(24)**	(38)
Nova Scotia Power Inc. ("NSPI") fuel adjustment mechanism ("FAM")	**(49)**	(123)
Net change in fair value ("FV") of derivative instruments	**540**	(185)
Net change in regulatory assets and liabilities	**229**	225
Net change in capitalized transportation capacity	**(521)**	(44)
Impairment charge	**-**	75
Loss on sale of Grand Bahama Power Company Limited (“GBPC”), excluding transaction costs (note 3)	**24**	-
Gain on sale of New Mexico Gas Company ("NMGC"), excluding transaction costs (note 3)	**(35)**	-
Other operating activities, net	**(14)**	21
Changes in non-cash working capital (note 22)	**315**	(382)
Net cash provided by operating activities	**2,428**	1,590
Investing activities		
Additions to PP&E	**(2,748)**	(2,566)
Proceeds on disposal of assets	**16**	47
Proceeds from dispositions (note 3)	**1,141**	-
Other investing activities	**(4)**	1
Net cash used in investing activities	**(1,595)**	(2,518)
Financing activities		
Change in short-term debt, net	**585**	(347)
Proceeds from short-term debt with maturities greater than 90 days	**-**	500
Proceeds from long-term debt, net of issuance costs	**2,800**	919
Retirement of long-term debt	**(2,945)**	(176)
Net (repayments) proceeds under committed credit facilities	**(719)**	485
Issuance of common stock, net of issuance costs	**222**	40
Dividends on common stock	**(458)**	(423)
Dividends on preferred stock	**(60)**	(56)
Other financing activities	**2**	(1)
Net cash (used in) provided by financing activities	**(573)**	941
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**76**	(5)
Net increase in cash, cash equivalents, restricted cash, and cash associated with assets held for sale	**336**	8
Cash, cash equivalents, restricted cash and cash associated with assets held for sale, beginning of period	**371**	221
Cash, cash equivalents, and restricted cash, end of period	**$ 707**	$ 229
Cash, cash equivalents, restricted cash and cash associated with assets held for sale consists of:		
Cash	**$ 592**	$ 207
Short-term investments	**8**	5
Restricted cash	**107**	14
Cash associated with assets held for sale	**-**	3
Total	**$ 707**	$ 229

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

Emera Incorporated
Condensed Consolidated Statements of Changes in Equity (Unaudited)

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	NCI	Total Equity
For the three months ended September 30, 2026							
Balance, June 30, 2026	**$ 9,750**	**$ 1,422**	**$ 87**	**$ 1,280**	**$ 1,835**	**$ -**	**$ 14,374**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**203**	**-**	**203**
OCI, net of tax recovery of $1 million	**-**	**-**	**-**	**(48)**	**-**	**-**	**(48)**
Dividends declared on preferred stock (1)	**-**	**-**	**-**	**-**	**(21)**	**-**	**(21)**
Dividends declared on common stock ($0.7325/share)	**-**	**-**	**-**	**-**	**(225)**	**-**	**(225)**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discounts	**71**	**-**	**-**	**-**	**-**	**-**	**71**
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	**6**	**-**	**1**	**-**	**-**	**-**	**7**
Balance, September 30, 2026	**$ 9,827**	**$ 1,422**	**$ 88**	**$ 1,232**	**$ 1,792**	**$ -**	**$ 14,361**
For the nine months ended September 30, 2026							
Balance, December 31, 2025	**$ 9,387**	**$ 1,422**	**$ 86**	**$ 873**	**$ 1,614**	**$ 14**	**$ 13,396**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**909**	**-**	**909**
OCI, net of tax expense of $1 million	**-**	**-**	**-**	**359**	**-**	**-**	**359**
Dividends declared on preferred stock (2)	**-**	**-**	**-**	**-**	**(60)**	**-**	**(60)**
Dividends declared on common stock ($2.1975/share)	**-**	**-**	**-**	**-**	**(671)**	**-**	**(671)**
Issued under the DRIP, net of discounts	**213**	**-**	**-**	**-**	**-**	**-**	**213**
Issuance of common stock under the at-the-market ("ATM") program, net of after-tax issuance costs	**183**	**-**	**-**	**-**	**-**	**-**	**183**
Senior management stock options exercised and ECSPP	**44**	**-**	**2**	**-**	**-**	**-**	**46**
Sale of GBPC and associated preferred shares	**-**	**-**	**-**	**-**	**-**	**(14)**	**(14)**
Balance, September 30, 2026	**$ 9,827**	**$ 1,422**	**$ 88**	**$ 1,232**	**$ 1,792**	**$ -**	**$ 14,361**

(1) Series A; $0.3094/share, Series C; $0.4021/share, Series E; $0.2813/share, Series F; $0.3593/share; Series H; $0.3953/share; Series J; $0.3966/share and Series L; $0.2875/share
(2) Series A; $0.9282/share, Series C; $1.2064/share, Series E; $0.8438/share, Series F; $1.0779/share; Series H; $1.1858/share; Series J; $0.9279/share and Series L; $0.8625/share

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

Emera Incorporated
Condensed Consolidated Statements of Changes in Equity (Unaudited)

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	NCI	Total Equity
For the three months ended September 30, 2025							
Balance, June 30, 2025	$ 9,228	$ 1,422	$ 85	$ 660	$ 1,755	$ 14	$ 13,164
Net income of Emera Incorporated	-	-	-	-	247	1	248
OCI, net of tax expense of $3 million	-	-	-	225	-	-	225
Dividends declared on preferred stock (1)	-	-	-	-	(19)	-	(19)
Dividends declared on common stock ($0.7250/share)	-	-	-	-	(217)	-	(217)
Issued under the DRIP, net of discounts	72	-	-	-	-	-	72
Senior management stock options exercised and ECSPP	11	-	-	-	-	-	11
Other	1	-	-	-	-	(1)	-
Balance, September 30, 2025	$ 9,312	$ 1,422	$ 85	$ 885	$ 1,766	$ 14	$ 13,484
For the nine months ended September 30, 2025							
Balance, December 31, 2024	$ 9,042	$ 1,422	$ 84	$ 1,261	$ 1,468	$ 14	$ 13,291
Net income of Emera Incorporated	-	-	-	-	1,002	1	1,003
OCI, net of tax recovery of $6 million	-	-	-	(376)	-	-	(376)
Dividends declared on preferred stock (2)	-	-	-	-	(56)	-	(56)
Dividends declared on common stock ($2.1750/share)	-	-	-	-	(648)	-	(648)
Issued under the DRIP, net of discount	225	-	-	-	-	-	225
Issuance under ATM program, net of after-tax issuance costs	10	-	-	-	-	-	10
Senior management stock options exercised and ECSPP	34	-	1	-	-	-	35
Other	1	-	-	-	-	(1)	-
Balance, September 30, 2025	$ 9,312	$ 1,422	$ 85	$ 885	$ 1,766	$ 14	$ 13,484

(1) Series A; $0.1364/share, Series B; $0.2789/share, Series C; $0.4021/share, Series E; $0.2813/share, Series F; $0.3593/share; Series H; $0.3953/share; Series J; $0.2656/share and Series L; $0.2875/share
(2) Series A; $0.4092/share, Series B; $0.9451/share, Series C; $1.2064/share, Series E; $0.8438/share, Series F; $0.9813/share; Series H; $1.1858/share; Series J; $0.7969/share and Series L; $0.8625/share

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Emera Incorporated ("Emera" or the "Company") is an energy and services company that invests in electricity generation, transmission and distribution, and gas transmission and distribution. At September 30, 2026, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility in West Central Florida.

- Canadian Electric Utilities, which includes:
    - NSPI, a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia;
    - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion, including AFUDC, transmission project between the island of Newfoundland and Nova Scotia; and
    - a 50 per cent indirect voting equity interest in Wasoqonatl Transmission Incorporated ("WTI"), a transmission line project to create a reliability intertie between Nova Scotia and New Brunswick.

- Gas Utilities and Infrastructure, which includes:
    - Peoples Gas System, Inc. ("PGS"), a regulated gas distribution utility operating across Florida;
    - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States ("US") border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy"), which expires in 2034;
    - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
    - a 12.9 per cent equity interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline that transports natural gas throughout markets in Atlantic Canada and the northeastern US.

On August 12, 2026 Emera completed the sale of New Mexico Gas Company, Inc. ("NMGC"), which was previously included in the Gas Utilities and Infrastructure segment. For more information on the transaction, refer to note 3;

- Other Electric Utilities, which includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
    - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated regulated electric utility on the island of Barbados; and
    - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

On May 12, 2026, Emera completed the sale of GBPC which was previously included in the Other Electric Utilities segment. For further details, refer to note 3;

- Emera's other segment includes investments in energy-related non-regulated companies that are below the required threshold for reporting as separate segments and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments. This includes:
    - Emera Energy, which consists of:
        - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
        - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
        - a 50 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
    - Emera US Finance LP, Emera US Finance, LLC ("Emera Finance"), EUSHI Finance, Inc. ("EUSHI Finance") and TECO Finance, Inc., financing subsidiaries of Emera;
    - Emera US Holdings Inc. ("EUSHI"), a wholly owned holding company for certain of Emera's assets located in the US; and
    - Other investments.

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.

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.

The closing of the CU Transaction 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.

Basis of Presentation

These unaudited condensed consolidated interim financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles (“USGAAP”). The significant accounting policies applied to these unaudited condensed consolidated interim financial statements are consistent with those disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2025.

In the opinion of management, these unaudited condensed consolidated interim financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2026.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

Use of Management 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 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 audited consolidated financial statements.

Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year, primarily due to seasonal factors. Electricity and gas sales, and related transmission and distribution, vary during the year. The first quarter provides strong earnings contributions from the Canadian Electric Utilities and Gas Utilities and Infrastructure segments, where winter is the peak electricity and gas usage season. The third quarter provides strong earnings contributions from the Florida Electric Utility segment due to summer being the heaviest electric consumption season. Certain quarters may also be impacted by weather and the number and severity of storms.

Cybersecurity Incident

On April 25, 2025, Emera and NSPI discovered a cybersecurity incident (the “Cybersecurity Incident”) involving unauthorized access into certain parts of its Canadian information technology (“IT”) network and servers supporting portions of its business applications. There was no disruption to the Canadian physical operations or to 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. The Company maintains cyber insurance coverage and is working with its insurer on the claims process.

2. 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.

3. DISPOSITIONS

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). This was recorded in “Other income, net” on the Condensed Consolidated Statements of Income and included in the “Other” segment.

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. The outcome of the appeal process remains uncertain.

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. A total of $144 million ($104 million USD) of depreciation and amortization was recorded on these assets from August 5, 2024, the date they were classified as held for sale, through 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 included in the Gas Utilities and Infrastructure segment.

On June 30, 2025, as a result of the then-pending sale, the Company remeasured the NMGC disposal group at the lower of its carrying amount and FV less costs to sell by comparing the FV of expected transaction proceeds to the carrying value of net assets. As a result of the change in the expected timing of the transaction close, a non-cash impairment charge of $75 million ($71 million, after-tax) or $55 million USD ($52 million USD, after-tax) was recorded in “Impairment charge” on the Condensed Consolidated Statements of Income in Q2 2025.

In Q2 2025, an additional loss for estimated future transaction costs of $2 million ($1 million after-tax) was recorded in “Other income, net” on the Condensed Consolidated Statements of Income.

Sale of GBPC

On May 12, 2026, Emera completed the sale of GBPC. As a result of the sale, Emera recognized a loss of $25 million after transaction costs ($24 million, after-tax and transaction costs). This was recorded in “Other income, net” on the Condensed Consolidated Statements of Income and included in the “Other Electric Utilities” and “Other” segments.

4. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part to their different operating, regulatory and geographical environments. Segments are reported based on each subsidiary’s contribution of revenues, net income attributable to common shareholders and total assets, as reported to the Company’s chief operating decision maker (“CODM”). Emera’s CODM is the Chief Executive Officer.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2026							
Operating revenues from external customers (1)	$ 1,248	$ 412	$ 312	$ 122	$ (110)	$ -	$ 1,984
Inter-segment revenues (1)	2	-	6	-	7	(15)	-
Total operating revenues	1,250	412	318	122	(103)	(15)	1,984
Regulated fuel for generation and purchased power	307	201	-	76	-	(6)	578
Regulated cost of natural gas	-	-	52	-	-	-	52
OM&G	235	103	103	23	52	(18)	498
Provincial, state and municipal taxes	91	13	26	1	1	-	132
Depreciation and amortization	188	73	47	12	1	-	321
Income from equity investments	-	11	3	1	5	-	20
Other income (expense), net	19	11	2	(4)	38	(9)	57
Interest expense, net (2)	83	33	37	1	96	-	250
Income tax expense (recovery)	61	(6)	16	-	(44)	-	27
Preferred stock dividends	-	-	-	-	21	-	21
Net income (loss) attributable to common shareholders	$ 304	$ 17	$ 42	$ 6	$ (187)	$ -	$ 182
For the nine months ended September 30, 2026							
Operating revenues from external customers (1)	$ 3,537	$ 1,472	$ 1,260	$ 382	$ 157	$ -	$ 6,808
Inter-segment revenues (1)	7	-	16	-	24	(47)	-
Total operating revenues	3,544	1,472	1,276	382	181	(47)	6,808
Regulated fuel for generation and purchased power	851	709	-	216	-	(17)	1,759
Regulated cost of natural gas	-	-	266	-	-	-	266
OM&G	804	341	354	88	144	(39)	1,692
Provincial, state and municipal taxes	261	38	92	3	1	-	395
Depreciation and amortization	561	227	155	48	5	-	996
Income from equity investments	-	33	13	3	24	-	73
Other income (expense), net	54	23	8	(17)	4	(9)	63
Interest expense, net (2)	246	115	113	10	312	-	796
Income tax expense (recovery)	130	(21)	84	-	(62)	-	131
Preferred stock dividends	-	-	-	-	60	-	60
Net income (loss) attributable to common shareholders	$ 745	$ 119	$ 233	$ 3	$ (251)	$ -	$ 849
As at September 30, 2026							
Total assets	$ 27,164	$ 8,971	$ 6,777	$ 1,031	$ 2,862	$ (1,179)	$ 45,626
Investments subject to significant influence	$ -	$ 467	$ 109	$ 58	$ -	$ -	$ 634
Goodwill	$ 4,964	$ -	$ 812	$ -	$ -	$ -	$ 5,776

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs of $7 million for the three months ended September 30, 2026, and $20 million for the nine months ended September 30, 2026 between the Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2025							
Operating revenues from external customers (1)	$ 1,266	$ 405	$ 314	$ 159	$ (38)	$ -	$ 2,106
Inter-segment revenues (1)	3	-	5	-	7	(15)	-
Total operating revenues	1,269	405	319	159	(31)	(15)	2,106
Regulated fuel for generation and purchased power	281	189	-	83	-	(6)	547
Regulated cost of natural gas	-	-	53	-	-	-	53
OM&G	315	98	113	36	25	(9)	578
Provincial, state and municipal taxes	84	12	26	1	1	-	124
Depreciation and amortization	176	74	52	21	1	-	324
Income from equity investments	-	10	4	1	-	-	15
Other income, net	19	11	3	3	(17)	-	19
Interest expense, net (2)	79	45	37	5	94	-	260
Income tax expense (recovery)	51	(5)	13	-	(53)	-	6
NCI	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	19	-	19
Net income (loss) attributable to common shareholders	$ 302	$ 13	$ 32	$ 16	$ (135)	$ -	$ 228
For the nine months ended September 30, 2025							
Operating revenues from external customers (1)	$ 3,353	$ 1,440	$ 1,282	$ 435	$ 260	$ -	$ 6,770
Inter-segment revenues (1)	8	-	13	-	23	(44)	-
Total operating revenues	3,361	1,440	1,295	435	283	(44)	6,770
Regulated fuel for generation and purchased power	772	671	-	223	-	(13)	1,653
Regulated cost of natural gas	-	-	346	-	-	-	346
OM&G	821	327	350	110	90	(25)	1,673
Provincial, state and municipal taxes	237	37	86	3	1	-	364
Depreciation and amortization	523	221	152	58	5	-	959
Income from equity investments	-	32	14	3	(1)	-	48
Other income, net	66	25	9	5	24	6	135
Interest expense, net (2)	226	129	112	15	282	-	764
Impairment charge	-	-	-	-	75	-	75
Income tax expense (recovery)	122	(39)	72	3	(42)	-	116
NCI	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	56	-	56
Net income (loss) attributable to common shareholders	$ 726	$ 151	$ 200	$ 30	$ (161)	$ -	$ 946
As at December 31, 2025							
Total assets	$ 24,636	$ 8,546	$ 8,476	$ 1,439	$ 2,469	$ (749)	$ 44,817
Investment subject to significant influence	$ -	$ 464	$ 100	$ 52	$ -	$ 18	$ 634
Goodwill	$ 4,796	$ -	$ 784	$ -	$ -	$ -	$ 5,580

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs of $6 million for the three months ended September 30, 2025, and $20 million for the nine months ended September 30, 2025 between the Gas Utilities and Infrastructure and Other segments.

5. REVENUE

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

millions of dollars	Electric: Florida Electric Utility	Electric: Canadian Electric Utilities	Electric: Other Electric Utilities	Gas: Gas Utilities and Infrastructure	Other: Other	Other: Inter-Segment Eliminations	Total
For the three months ended September 30, 2026							
Regulated Revenue							
Residential	$ 786	$ 207	$ 46	$ 108	$ -	$ -	$ 1,147
Commercial	325	118	73	100	-	-	616
Industrial	71	66	-	25	-	(6)	156
Other electric	110	10	-	-	-	-	120
Regulatory deferrals	(49)	-	-	-	-	-	(49)
Other (1)	7	11	3	64	-	(2)	83
Finance income (2)(3)	-	-	-	16	-	-	16
Regulated revenue	1,250	412	122	313	-	(8)	2,089
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	(3)	-	(3)
Other non-regulated operating revenue	-	-	-	5	13	(9)	9
Mark-to-market (3)	-	-	-	-	(113)	2	(111)
Non-regulated revenue	-	-	-	5	(103)	(7)	(105)
Total operating revenues	**$ 1,250**	**$ 412**	**$ 122**	**$ 318**	**$ (103)**	**$ (15)**	**$ 1,984**
For the nine months ended September 30, 2026							
Regulated Revenue							
Residential	$ 2,013	$ 809	$ 138	$ 529	$ -	$ -	$ 3,489
Commercial	904	401	213	380	-	-	1,898
Industrial	206	199	10	76	-	(16)	475
Other electric	470	35	3	-	-	-	508
Regulatory deferrals	(68)	-	9	-	-	-	(59)
Other (1)	19	28	9	229	-	(7)	278
Finance income (2)(3)	-	-	-	46	-	-	46
Regulated revenue	3,544	1,472	382	1,260	-	(23)	6,635
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	152	-	152
Other non-regulated operating revenue	-	-	-	16	35	(26)	25
Mark-to-market (3)	-	-	-	-	(6)	2	(4)
Non-regulated revenue	-	-	-	16	181	(24)	173
Total operating revenues	**$ 3,544**	**$ 1,472**	**$ 382**	**$ 1,276**	**$ 181**	**$ (47)**	**$ 6,808**

(1) Other includes rental revenues which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-Segment Eliminations	Total
			Electric	**Gas**		**Other**	
For the three months ended September 30, 2025							
Regulated Revenue							
Residential	$ 787	$ 197	$ 59	$ 116	$ -	$ -	$ 1,159
Commercial	323	122	81	103	-	-	629
Industrial	71	68	7	26	-	(6)	166
Other electric	117	10	2	-	-	-	129
Regulatory deferrals	(35)	-	7	-	-	-	(28)
Other (1)	6	8	3	52	-	(3)	66
Finance income (2)(3)	-	-	-	16	-	-	16
Regulated revenue	1,269	405	159	313	-	(9)	2,137
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	(3)	-	(3)
Other non-regulated operating revenue	-	-	-	6	9	(8)	7
Mark-to-market (3)	-	-	-	-	(37)	2	(35)
Non-regulated revenue	-	-	-	6	(31)	(6)	(31)
Total operating revenues	$ 1,269	$ 405	$ 159	$ 319	$ (31)	$ (15)	$ 2,106
For the nine months ended September 30, 2025							
Regulated Revenue							
Residential	$ 1,909	$ 788	$ 152	$ 568	$ -	$ -	$ 3,417
Commercial	858	390	231	395	-	-	1,874
Industrial	205	203	21	76	-	(14)	491
Other electric	384	32	6	-	-	-	422
Regulatory deferrals	(13)	-	16	-	-	-	3
Other (1)	18	27	9	190	-	(8)	236
Finance income (2)(3)	-	-	-	48	-	-	48
Regulated revenue	3,361	1,440	435	1,277	-	(22)	6,491
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	98	-	98
Other non-regulated operating revenue	-	-	-	18	25	(21)	22
Mark-to-market (3)	-	-	-	-	160	(1)	159
Non-regulated revenue	-	-	-	18	283	(22)	279
Total operating revenues	$ 3,361	$ 1,440	$ 435	$ 1,295	$ 283	$ (44)	$ 6,770

(1) Other includes rental revenues which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations:

Remaining performance obligations primarily represent gas transportation contracts, and long-term steam supply arrangements with fixed contract terms. As of September 30, 2026, the aggregate amount of the transaction price allocated to remaining performance obligations was $327 million (2025 – $452 million). This amount includes $118 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040, and $38 million of future performance obligations related to asset management agreements between PGS and EES through 2030. This amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2040.

6. REGULATORY ASSETS AND LIABILITIES

A summary of regulatory assets and liabilities is provided below. For a detailed description regarding the nature of the Company's regulatory assets and liabilities, refer to note 7 in Emera's 2025 annual audited consolidated financial statements. Updates to regulatory environments are included below.

As at millions of dollars	**September 30 2026**	December 31 2025
Regulatory assets (2)		
Deferred income tax regulatory assets	**$ 1,468**	$ 1,385
TEC capital cost recovery for early retired assets	**762**	727
Pension and post-retirement medical plan	**317**	316
TEC capital cost recovery for retired Polk Unit 1 components	**169**	178
NSPI FAM	**151**	102
Storm cost recovery clauses	**38**	206
Cost recovery clauses	**35**	55
Environmental remediations	**27**	27
Deferrals related to derivative instruments	**17**	36
Stranded cost recovery	**-**	25
Other (1)	**163**	141
	$ 3,147	$ 3,198
Current	**$ 237**	$ 409
Long-term	**2,910**	2,789
Total regulatory assets	**$ 3,147**	$ 3,198
Regulatory liabilities (2)		
Accumulated reserve – cost of removal	**$ 800**	$ 729
Deferred income tax regulatory liabilities	**744**	751
Cost recovery clauses	**84**	75
Storm cost recovery clauses	**79**	-
Deferrals related to derivative instruments	**47**	25
BLPC Self-insurance fund ("SIF") (note 23)	**31**	30
Other (1)	**42**	59
	$ 1,827	$ 1,669
Current	**$ 245**	$ 211
Long-term	**1,582**	1,458
Total regulatory liabilities	**$ 1,827**	$ 1,669

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

(2) NMGC's assets and liabilities were classified as held for sale beginning in Q3 2024 and excluded from the table above as at December 31, 2025. For further details on the transaction, refer to note 3.

Florida Electric Utility

On September 30, 2026, TEC petitioned the FPSC for approval of Large Load Customer Tariffs in accordance with Florida's data center law, Senate Bill 484, which requires public utilities to establish a minimum tariff and service requirement for large-load customers.

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.

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.

Canadian Electric Utilities

NSPI

Securitization Application:
On October 9, 2026, NSPI applied to the Nova Scotia Energy Board ("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"). The Proposed Securitized Assets include those within the scope of NSPI's Decarbonization Deferral Account as of December 31, 2025, the FAM balance and a pre-payment of 2026-2027 fuel costs, the regulatory assets defined below for the Securitization Deferral, IESO Nova Scotia Assessment Deferral and ELIADC Deferral (as defined below), and financing costs associated with the securitization transaction. NSPI requested the implementation of the Securitization Rider to begin, on an interim basis, on January 1, 2027, subject to an annual rate-setting application. The NSEB has 60 days following the application to provide a decision on the financing order.

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.

General Rate Application ("GRA"):
On April 30, 2026, the NSEB approved the GRA with changes effective May 1, 2026. This results in an average annual customer rate increase of 1.2 per cent, and a further average increase of 2.5 per cent on January 1, 2027. Any under or over-recovery of fuel costs will be addressed through NSPI's established FAM process with the NSEB. NSPI's return on equity 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").

Extra Large Industrial Active Demand Control Customer Deferral ("ELIADC" Deferral):
On April 30, 2026, the NSEB approved the establishment of a regulatory asset allowing NSPI to defer revenue variances arising from differences between the current rate setting methodology for an ELIADC customer and a revised NSEB-approved methodology. The deferral is effective from May 1, 2026, until the earlier of December 31, 2027, or implementation of an approved methodology change. Amounts are recorded in "Regulated fuel for generation and purchased power" on the Condensed Consolidated Income Statement and the balance deferred as a "Regulatory Asset" on the Condensed Consolidated Balance Sheet.

NSPML

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 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.

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.

Gas Utilities and Infrastructure

PGS

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

Other Electric Utilities

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.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value as at September 30 2026	Carrying Value as at December 31 2025	Equity Income for the three months ended September 30 2026	Equity Income for the three months ended September 30 2025	Equity Income (loss) for the nine months ended September 30 2026	Equity Income (loss) for the nine months ended September 30 2025	Percentage of Ownership 2026
NSPML	**$ 458**	$ 462	**$ 10**	$ 10	**$ 32**	$ 32	100.0
M&NP (1)	**109**	108	**3**	4	**13**	14	12.9
Lucelec (1)	**58**	55	**1**	1	**3**	3	19.5
WTI (2)	**9**	9	**1**	-	**1**	-	50.0
Bear Swamp (3)	**-**	-	**5**	-	**24**	(1)	50.0
	$ 634	$ 634	**$ 20**	$ 15	**$ 73**	$ 48	

(1) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, records its investment in these entities using the equity method.
(2) NSPI has a 50 per cent indirect voting interest in WTI. As of September 30, 2026, NSPI's economic interest based on the $9 million invested is 4 per cent.
(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $86 million (December 31, 2025 – $84 million) is recorded in Other long-term liabilities on the Condensed Consolidated Balance Sheets.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 23). NSPML's consolidated summarized balance sheet is as follows:

As at millions of dollars	September 30 2026	December 31 2025
Current assets	**$ 97**	$ 40
PP&E	**1,359**	1,380
Regulatory assets	**760**	782
Non-current assets	**26**	27
Total assets	**$ 2,242**	$ 2,229
Current liabilities	**$ 119**	$ 87
Long-term debt (1)	**1,466**	1,495
Non-current liabilities	**199**	185
Equity	**458**	462
Total liabilities and equity	**$ 2,242**	$ 2,229

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

8. OTHER INCOME, NET

For the millions of dollars	Three months ended September 30 2026	Three months ended September 30 2025	Nine months ended September 30 2026	Nine months ended September 30 2025
Gain (loss) on sale of NMGC after transaction costs (1)	**$ 35**	$ -	**$ 35**	$ (2)
AFUDC - equity	**14**	12	**39**	49
Interest income	**4**	8	**15**	28
Pension non-service (expense) recovery	**(3)**	7	**7**	21
Loss on sale of GBPC (1)	**(4)**	-	**(25)**	-
FX (losses) gains	**-**	(17)	**(29)**	23
Other	**11**	9	**21**	16
	$ 57	$ 19	**$ 63**	$ 135

(1) For more information on the sale of NMGC and GBPC, refer to note 3.

9. INCOME TAXES

The income tax provision, for the three and nine months ended September 30, differs from that computed using the enacted Canadian federal statutory income tax rate for the following reasons:

For the millions of dollars	Three months ended September 30 2026		Three months ended September 30 2025		Nine months ended September 30 2026		Nine months ended September 30 2025	
Income before provision for income taxes	**$ 230**		$ 254		**$ 1,040**		$ 1,119	
Income taxes, at statutory income tax rate	**35**	**15 %**	38	15 %	**156**	**15 %**	168	15 %
Domestic reconciling items:								
Investment tax credits	**(3)**	**(1) %**	(4)	(2) %	**(14)**	**(1) %**	(33)	(3) %
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(2)**	**(1) %**	(1)	- %	**(13)**	**(1) %**	(15)	(1) %
Net Part VI. Tax	**3**	**1 %**	4	2 %	**11**	**1 %**	11	1 %
Valuation allowance	**2**	**1 %**	(3)	(1) %	**(4)**	**- %**	(8)	(2) %
Other	**(2)**	**(1) %**	(1)	- %	**(4)**	**- %**	(7)	(1) %
Provincial income taxes (1)	**(25)**	**(11) %**	(20)	(8) %	**(21)**	**(2) %**	(1)	- %
Foreign reconciling items:								
United States								
Federal tax rate variance	**23**	**10 %**	20	8 %	**59**	**6 %**	49	4 %
Production tax credits	**(22)**	**(10) %**	(18)	(7) %	**(53)**	**(6) %**	(44)	(4) %
State income tax, net of federal income tax benefit	**16**	**7 %**	15	6 %	**42**	**4 %**	40	4 %
Amortization of deferred income tax regulatory liabilities	**(13)**	**(6) %**	(14)	(6) %	**(31)**	**(3) %**	(35)	(3) %
Investment tax credits	**(1)**	**- %**	(2)	(1) %	**(20)**	**(2) %**	(39)	(3) %
Additional impact from the sale of NMGC	**15**	**7 %**	-	- %	**15**	**1 %**	-	- %
Valuation allowance	**9**	**4 %**	-	- %	**9**	**1 %**	-	- %
Deferral and amortization of investment tax credits	**(6)**	**(3) %**	(6)	(3) %	**3**	**- %**	23	2 %
Impairment charge	**-**	**- %**	-	- %	**-**	**- %**	13	1 %
Other	**(1)**	**- %**	-	- %	**(3)**	**- %**	(3)	- %
Other foreign jurisdictions	**(1)**	**- %**	(2)	(1) %	**(1)**	**- %**	(3)	- %
Income tax expense (recovery)	**$ 27**	**12 %**	$ 6	2 %	**$ 131**	**13 %**	$ 116	10 %

(1) The majority of provincial income taxes relate to Nova Scotia.

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 (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 for the nine months ended September 30, 2026.

10. COMMON STOCK

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

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 ECSPP	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.

11. EARNINGS PER SHARE

The following table reconciles the computation of basic and diluted earnings per share:

	Three months ended		Nine months ended	
For the	September 30		September 30	
millions of dollars (except per share amounts)	**2026**	2025	**2026**	2025
Numerator				
Net income attributable to common shareholders	**$ 182.3**	$ 227.5	**$ 849.0**	$ 945.9
Diluted numerator	**182.3**	227.5	**849.0**	945.9
Denominator				
Weighted average shares of common stock outstanding – basic	**307.7**	299.9	**305.8**	298.5
Stock-based compensation	**0.9**	0.7	**1.0**	0.5
Weighted average shares of common stock outstanding – diluted	**308.6**	300.6	**306.8**	299.0
Earnings per common share				
Basic	**$ 0.59**	$ 0.76	**$ 2.78**	$ 3.17
Diluted	**$ 0.59**	$ 0.76	**$ 2.77**	$ 3.16

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI, net of tax, are as follows:

millions of dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	Gains (losses) on derivatives recognized as cash flow hedges	Net change in available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the nine months ended September 30, 2026						
Balance, January 1, 2026	**$ 773**	**$ (81)**	**$ 10**	**$ 2**	**$ 169**	**$ 873**
OCI before reclassifications	**466**	**(71)**	**-**	**(1)**	**-**	**394**
Amounts reclassified from AOCI	**(25)**	**-**	**(1)**	**-**	**(9)**	**(35)**
Net current period OCI	**441**	**(71)**	**(1)**	**(1)**	**(9)**	**359**
Balance, September 30, 2026	**$ 1,214**	**$ (152)**	**$ 9**	**$ 1**	**$ 160**	**$ 1,232**
For the nine months ended September 30, 2025						
Balance, January 1, 2025	$ 1,396	$ (163)	$ 12	$ -	$ 16	$ 1,261
OCI before reclassifications	(428)	56	-	1	-	(371)
Amounts reclassified from AOCI	-	-	(2)	-	(3)	(5)
Net current period OCI	(428)	56	(2)	1	(3)	(376)
Balance, September 30, 2025	$ 968	$ (107)	$ 10	$ 1	$ 13	$ 885

The reclassifications out of AOCI are as follows:

For the millions of dollars		Three months ended September 30 **2026**	Three months ended September 30 2025	Nine months ended September 30 **2026**	Nine months ended September 30 2025
	Affected line item in the Condensed Consolidated Interim Financial Statements	Amounts reclassified from AOCI			
Realized gain on translation of self-sustaining foreign operations					
Gain on disposition	Other (expenses) income, net	**$ -**	$ -	**$ (25)**	$ -
Gain on derivatives recognized as cash flow hedges					
Interest rate hedge	Interest expense, net	**$ -**	$ (1)	**$ (1)**	$ (2)
Net change in unrecognized pension and post-retirement benefit costs					
Amounts reclassified into obligations	Pension and post-retirement benefits	**(6)**	1	**(11)**	(3)
	Income tax recovery	**2**	-	**2**	
Total reclassifications out of AOCI, for the period		**$ (4)**	$ -	**$ (35)**	$ (5)

13. DERIVATIVE INSTRUMENTS

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange (“FX”) fluctuations on foreign currency denominated purchases and sales;
- interest rate fluctuations on debt securities; and
- share price fluctuations on stock-based compensation.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered “derivatives”. The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the normal purchases normal sales (“NPNS”) exemption are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Company’s business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exemption and will discontinue treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at FV on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. Specifically, for cash flow hedges, the change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized.

   Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

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

4. Derivatives that do not meet any of the above criteria are designated as held-for-trading (“HFT”) derivatives and are recorded on the balance sheet at FV, with changes normally recorded in net income of the period, unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of dollars	**September 30 2026**	December 31 2025	**September 30 2026**	December 31 2025
Regulatory deferral:				
Commodity swaps and forwards	**$ 39**	$ 22	**$ 17**	$ 33
FX forwards	**8**	3	**-**	2
	47	25	**17**	35
HFT derivatives:				
Power swaps and physical contracts	**26**	51	**27**	50
Natural gas swaps, futures, forwards, physical contracts	**246**	238	**1,243**	695
	272	289	**1,270**	745
Other derivatives:				
Equity derivatives	**9**	8	**-**	-
FX forwards	**-**	8	**16**	1
	9	16	**16**	1
Total gross derivatives	**328**	330	**1,303**	781
Impact of master netting agreements:				
Regulatory deferral	**(1)**	(1)	**(1)**	(1)
HFT derivatives	**(92)**	(131)	**(92)**	(131)
Total impact of master netting agreements	**(93)**	(132)	**(93)**	(132)
Total derivatives	**$ 235**	$ 198	**$ 1,210**	$ 649
Current (1)	**196**	156	**823**	534
Long-term (1)	**39**	42	**387**	115
Total derivatives	**$ 235**	$ 198	**$ 1,210**	$ 649

(1) Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of $19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles. As of September 30, 2026, the unrealized gain in 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. The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months.

Regulatory Deferral

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

millions of dollars	**Commodity swaps and forwards**	**FX forwards**	Commodity swaps and forwards	FX forwards
For the three months ended September 30		**2026**		2025
Unrealized (loss) gain in regulatory assets	**$ (7)**	**$ (1)**	$ (17)	$ 4
Unrealized (loss) gain in regulatory liabilities	**(2)**	**2**	(7)	6
Realized gain in regulatory assets	**-**	**-**	(2)	-
Realized loss (gain) in regulatory liabilities	**(1)**	**-**	2	-
Realized loss (gain) in inventory (1)	**(1)**	**(2)**	3	(1)
Realized loss (gain) in regulated fuel for generation and purchased power (2)	**4**	**(1)**	7	(1)
Total change in derivative instruments	**$ (7)**	**$ (2)**	$ (14)	$ 8

For the nine months ended September 30				
		2026		2025
Unrealized (loss) gain in regulatory assets	**$ (5)**	**$ 3**	$ (32)	$ 3
Unrealized (loss) gain in regulatory liabilities	**47**	**8**	10	(12)
Realized gain in regulatory assets	**-**	**-**	(5)	-
Realized loss (gain) in regulatory liabilities	**(12)**	**-**	5	-
Realized loss (gain) in inventory (1)	**2**	**(2)**	10	(5)
Realized loss (gain) in regulated fuel for generation and purchased power (2)	**1**	**(2)**	15	(3)
Total change in derivative instruments	**$ 33**	**$ 7**	$ 3	$ (17)

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period and hedging relationships that have been terminated or the hedged transaction is no longer probable.

As at September 30, 2026, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2026	2027-2028
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	2	14
Power (MWh)	-	1
FX forwards:		
FX contracts (millions of USD)	$ 67	$ 144
Weighted average rate	1.3434	1.3669
% of USD requirements	76%	31%

HFT Derivatives

The Company has recognized the following realized and unrealized gains with respect to HFT derivatives:

For the millions of dollars	Three months ended September 30 **2026**	2025	Nine months ended September 30 **2026**	2025
Power swaps and physical contracts in non-regulated operating revenues	**$ (1)**	$ 3	**$ 4**	$ 3
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(468)**	13	**(93)**	477
Total gains (losses) in net income	**$ (469)**	$ 16	**$ (89)**	$ 480

As at September 30, 2026, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2026	2027	2028	2029	2030 and thereafter
Natural gas purchases (MMBtu)	144	214	58	50	129
Natural gas sales (MMBtu)	185	264	51	34	201
Power sales (MWh)	1	1	-	-	-

Other Derivatives

As at September 30, 2026, the Company had equity derivatives in place to manage cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 3.2 million shares and extends until December of 2026. The FX forwards have a combined notional amount of $466 million USD and expire in 2026 through 2028.

The Company has recognized the following realized and unrealized gains (losses) with respect to other derivatives:

millions of dollars	**FX forwards**	**Equity derivatives**	FX forwards	Equity derivatives
For the three months ended September 30		**2026**		2025
Unrealized (loss) gain in OM&G	**$ -**	**$ (23)**	$ -	$ 11
Unrealized (loss) gain in other income, net	**2**	**-**	(14)	-
Realized loss in other income, net	**-**	**-**	(2)	-
Total (losses) gains in net income	**$ 2**	**$ (23)**	$ (16)	$ 11

For the nine months ended September 30				2026		2025
Unrealized gain in OM&G	**$**	**-**	**$**	**1**	$ -	$ 36
Unrealized gain (loss) in other income, net		**(21)**		**-**	33	-
Realized loss in other income, net		**-**		**-**	(12)	-
Total (losses) gains in net income	**$**	**(21)**	**$**	**1**	$ 21	$ 36

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits, and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high-risk accounts.

The Company assesses the potential for credit losses on a regular basis and, where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, FX and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements, North American Energy Standards Board agreements and/or Edison Electric Institute agreements. The Company believes entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at September 30, 2026, the Company had $261 million (December 31, 2025 – $207 million) in financial assets considered to be past due, which had been outstanding for an average 87 days. The FV of these financial assets was $249 million (December 31, 2025 – $192 million), the difference of which is included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

Cash Collateral

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

As at millions of dollars	**September 30 2026**	December 31 2025
Cash collateral provided to others	**$ 89**	$ 193
Cash collateral received from others	**$ 17**	$ 5

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at September 30, 2026, the total FV of derivatives in a liability position was $1,210 million (December 31, 2025 – $649 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

14. FV MEASUREMENTS

The Company is required to determine the FV of all derivatives except those which qualify for the NPNS exemption (see note 13) and uses a market approach to do so. The three levels of the FV hierarchy are defined as follows:

Level 1 – Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 – Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 – Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the FV measurement.

The following tables set out the classification of the methodology used by the Company to FV its derivatives:

As at millions of dollars	Level 1	Level 2	Level 3	September 30, 2026 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 23	$ 15	$ -	$ 38
FX forwards	-	8	-	8
	23	23	-	46
HFT derivatives:				
Power swaps and physical contracts	-	5	13	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	16	108	38	162
	16	113	51	180
Other derivatives:				
Equity derivatives	9	-	-	9
	9	-	-	9
Total assets	48	136	51	235
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	1	-	16
	15	1	-	16
HFT derivatives:				
Power swaps and physical contracts	-	8	11	19
Natural gas swaps, futures, forwards and physical contracts	7	91	1,061	1,159
	7	99	1,072	1,178
Other derivatives:				
FX forwards	-	16	-	16
	-	16	-	16
Total liabilities	22	116	1,072	1,210
Net assets (liabilities)	$ 26	$ 20	$ (1,021)	$ (975)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2025 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 21	$ -	$ -	$ 21
FX forwards	-	3	-	3
	21	3	-	24
HFT derivatives:				
Power swaps and physical contracts	(1)	29	7	35
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	88	34	123
	-	117	41	158
Other derivatives:				
FX forwards	-	8	-	8
Equity derivatives	8	-	-	8
	8	8	-	16
Total assets	29	128	41	198
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	11	21	-	32
FX forwards	-	2	-	2
	11	23	-	34
HFT derivatives:				
Power swaps and physical contracts	(4)	31	7	34
Natural gas swaps, futures, forwards and physical contracts	1	115	464	580
	(3)	146	471	614
Other derivatives:				
FX forwards	-	1	-	1
	-	1	-	1
Total liabilities	8	170	471	649
Net assets (liabilities)	$ 21	$ (42)	$ (430)	$ (451)

The change in the FV of the Level 3 financial assets and liabilities was as follows:

	Three months ended September 30, 2026 *HFT Derivatives*			Nine months ended September 30, 2026 *HFT Derivatives*		
millions of dollars	Power	Natural gas	**Total**	Power	Natural gas	**Total**
Assets						
Balance, beginning of period	$ 5	$ 11	**$ 16**	$ 7	$ 34	**$ 41**
Total net realized and unrealized gains included in non-regulated operating revenues	8	27	**35**	6	4	**10**
Balance, September 30, 2026	**$ 13**	**$ 38**	**$ 51**	**$ 13**	**$ 38**	**$ 51**
Liabilities						
Balance, beginning of period	$ 4	$ 337	**$ 341**	$ 7	$ 464	**$ 471**
Total net realized and unrealized losses included in non-regulated operating revenues	7	724	**731**	4	597	**601**
Balance, September 30, 2026	**$ 11**	**$ 1,061**	**$ 1,072**	**$ 11**	**$ 1,061**	**$ 1,072**

Significant unobservable inputs used in the FV measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) FV measurement. Other unobservable inputs used include internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers.

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

As at millions of dollars	FV		Significant Unobservable Input	September 30, 2026 Low	High	Weighted Average (1)
	Assets	**Liabilities**				
HFT derivatives – Power swaps and physical contracts	**13**	**11**	Third-party pricing	$34.96	$187.10	$97.40
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**38**	**1,061**	Third-party pricing	$1.33	$22.39	$10.33
Total	**$ 51**	**$ 1,072**				
Net liability		**$ 1,021**				

(1) Unobservable inputs were weighted by the relative FV of the instruments.

Long-term debt is a financial liability not measured at FV on the Condensed Consolidated Balance Sheets. The balance consisted of the following:

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
September 30, 2026	**$ 19,170**	**$ 17,400**	**$ -**	**$ 17,151**	**$ 249**	**$ 17,400**
December 31, 2025	$ 19,654	$ 18,956	$ -	$ 18,535	$ 421	$ 18,956

On August 11, 2026, Emera designated $750 million USD denominated intercompany balances related to the 2026 senior notes issued by Emera Finance, as a hedge of the foreign currency exposure of its net investment in its USD denominated operations.

On June 15, 2026, Emera redeemed all $1.2 billion USD denominated 2016 hybrid notes which were designated as a hedge of the foreign currency exposure of its net investment in USD denominated operations. On the same date, Emera designated $750 million USD denominated intercompany balances related to the 2026 hybrid notes issued by Emera Finance, as a hedge of the foreign currency exposure of its net investment in its USD denominated operations.

An after-tax foreign currency loss of $22 million was recorded in AOCI for the three months ended September 30, 2026 (2025 – $33 million after-tax loss) and an after-tax foreign currency loss of $71 million was recorded for the nine months ended September 30, 2026 (2025 – $56 million after-tax gain) related to Emera's net investment hedges.

15. RELATED PARTY TRANSACTIONS

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the 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.

- 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.

16. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars	**September 30 2026**	December 31 2025
Customer accounts receivable – billed	**$ 976**	$ 1,265
Customer accounts receivable – unbilled	**371**	400
Capitalized transportation capacity (1)	**556**	238
Cash collateral provided to others	**89**	193
Prepaid expenses	**151**	105
Sales tax receivable	**101**	84
Income tax receivable	**13**	19
Allowance for credit losses	**(12)**	(15)
Other	**227**	150
Total receivables and other current assets	**$ 2,472**	$ 2,439

(1) Capitalized transportation capacity represents the value of transportation/storage received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

17. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") pension plans, which cover substantially all of its employees. The Company also provides non-pension benefits for its retirees.

Emera's net periodic benefit cost included the following:

For the millions of dollars	Three months ended September 30 **2026**	2025	Nine months ended September 30 **2026**	2025
DB pension plans				
Service cost	**$ 9**	$ 9	**$ 27**	$ 27
Non-service cost:				
Interest cost	**28**	29	**85**	86
Expected return on plan assets	**(39)**	(40)	**(117)**	(122)
Current year amortization of:				
Actuarial losses	**1**	-	**2**	1
Regulatory asset	**3**	2	**11**	7
Settlements, Curtailments	**2**		**2**	
Total non-service costs	**(5)**	(9)	**(17)**	(28)
Total DB pension plans	**4**	-	**10**	(1)
Non-pension benefit plans				
Service cost	**1**	-	**2**	2
Interest cost	**3**	3	**9**	9
Expected return on plan assets	**-**	(1)	**(1)**	(2)
Current year amortization of:				
Actuarial losses / (gains)	**-**	-	**(1)**	-
Past Service Costs	**(1)**	-	**(1)**	(1)
Regulatory asset	**(2)**	-	**(2)**	-
Settlements, Curtailments	**(16)**	-	**(16)**	
Total non-service costs	**(16)**	2	**(12)**	6
Total non-pension benefit plans	**(15)**	2	**(10)**	8
Total DB pension and non-pension benefit plans	**$ (11)**	$ 2	**$ -**	$ 7

Emera's pension and non-pension contributions related to these DB plans for the three months ended September 30, 2026 were $18 million (2025 – $20 million), and for the nine months ended September 30, 2026 were $44 million (2025 – $47 million). Annual employer contributions to the DB pension plans are estimated to be $34 million for 2026. Emera's contributions related to the DC plans for the three months ended September 30, 2026 were $12 million (2025 – $13 million) and $38 million (2025 – $41 million) for the nine months ended September 30, 2026.

18. SHORT-TERM DEBT

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. For details regarding short-term debt, refer to note 24 in Emera's 2025 annual audited consolidated financial statements, and below for 2026 short-term debt financing activity.

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

Canadian Electric Utilities

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.

Other

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.

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.

19. LONG-TERM DEBT

For details regarding long-term debt, refer to note 26 in Emera's 2025 annual audited consolidated financial statements, and below for 2026 long-term debt financing activity.

Recent financing activities 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 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.

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 that bear interest at 4.91 per cent with a maturity date of May 5, 2031, $100 million USD senior notes that bear interest at 5.39 per cent with a maturity date of May 5, 2036, and $50 million USD senior notes that bear interest at 5.64 per cent with a maturity date of August 20, 2041.

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.

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 March 4, 2026, EUSHI Finance, Emera Finance, 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 LP’s $750 million USD 3.55 per cent senior unsecured note on June 15, 2026, upon maturity.

20. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2026, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Purchased power (1)	$ 79	$ 429	$ 410	$ 461	$ 454	$ 6,491	$ 8,324
Transportation (2)	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
Other	48	98	189	64	54	381	834
	$ 841	$ 1,844	$ 1,374	$ 1,152	$ 945	$ 9,996	$ 16,152

(1) Annual requirement to purchase electricity from Independent Power Producers or other utilities over varying contract lengths.

(2) 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.

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.

B. Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at September 30, 2026, the aggregate financial liability of the Florida utilities is estimated to be $16 million ($11 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of cleanup costs attributable to the Florida utilities. The estimates to perform the work are based on the Florida utilities' experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are believed to be currently credit-worthy and are likely to continue to be credit-worthy for the duration of remediation work. However, in those instances that they are not, the Florida utilities could be liable for more than their actual percentage of remediation costs. Other factors that could impact these estimates include additional testing and investigation which could expand the scope of cleanup activities, additional liability that might arise from cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in base rate proceedings.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Principal Financial Risks and Uncertainties

For information on principal financial risks which could materially affect the Company in the normal course of business, refer to note 28 in Emera's 2025 annual audited consolidated financial statements. Risks associated with derivative instruments and FV measurements are discussed in note 13 and note 14. There have been no material changes to the principal financial risks as of September 30, 2026.

D. Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2025 audited annual consolidated financial statements, 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.

21. CUMULATIVE PREFERRED STOCK

For details regarding cumulative preferred stock, refer to note 29 in Emera's 2025 annual audited consolidated financial statements, and below for 2026 preferred stock activity.

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"). There were 8.0 million Series J Shares outstanding.

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 were 8.0 million Series J Shares outstanding.

22. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of dollars	Nine months ended September 30 **2026**	2025
Changes in non-cash working capital:		
Inventory	**$ (61)**	$ (84)
Receivables and other current assets	**364**	(230)
Accounts payable	**(204)**	(169)
Other current liabilities	**216**	101
Total non-cash working capital	**$ 315**	$ (382)
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 213**	$ 225
Increase in accrued capital expenditures	**$ 59**	$ 28
Reclassification of short-term debt and current portion of long-term debt to long-term debt	**$ 70**	$ -
Supplemental disclosure of operating activities:		
Net change in short-term regulatory assets and liabilities	**$ 144**	$ 217

23. VARIABLE INTEREST ENTITIES

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have controlling financial interest of NSPML. When the critical milestones were achieved, NLH was deemed the primary beneficiary of the asset for financial reporting purposes, as it has authority over the majority of the direct activities expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC established a SIF, primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission, and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Condensed Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**September 30, 2026**		December 31, 2025	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 458**	**$ 6**	$ 462	$ 6

24. SUBSEQUENT EVENTS

These unaudited condensed consolidated interim financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through November 6, 2026, the date the unaudited condensed consolidated interim financial statements were issued.