EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2023 and 2022

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of dollars (except per share amounts)	Three months ended September 30 2023	2022	Nine months ended September 30 2023	2022
Operating revenues				
Regulated electric	**$ 1,598**	$ 1,489	**$ 4,333**	$ 4,111
Regulated gas	**257**	338	**1,100**	1,179
Non-regulated	**(115)**	8	**158**	(60)
Total operating revenues (note 5)	**1,740**	1,835	**5,591**	5,230
Operating expenses				
Regulated fuel for generation and purchased power	**530**	612	**1,401**	1,630
Regulated cost of natural gas	**58**	149	**392**	554
Operating, maintenance and general expenses ("OM&G")	**497**	399	**1,398**	1,164
Provincial, state and municipal taxes	**117**	98	**326**	275
Depreciation and amortization	**266**	238	**785**	698
Total operating expenses	**1,468**	1,496	**4,302**	4,321
Income from operations	**272**	339	**1,289**	909
Income from equity investments (note 7)	**32**	32	**103**	92
Other income (expense), net	**15**	(1)	**107**	43
Interest expense, net (note 8)	**235**	184	**684**	503
Income before provision for income taxes	**84**	186	**815**	541
Income tax (recovery) expense (note 9)	**(34)**	2	**77**	31
Net income	**118**	184	**738**	510
Non-controlling interest in subsidiaries	**1**	1	**1**	1
Preferred stock dividends	**16**	16	**48**	47
Net income attributable to common shareholders	**$ 101**	$ 167	**$ 689**	$ 462
Weighted average shares of common stock outstanding (in millions) (note 11)				
Basic	**273.6**	266.6	**272.2**	264.3
Diluted	**273.8**	267.0	**272.5**	264.8
Earnings per common share (note 11)				
Basic	**$ 0.37**	$ 0.63	**$ 2.53**	$ 1.75
Diluted	**$ 0.37**	$ 0.63	**$ 2.53**	$ 1.74
Dividends per common share declared	**$ 0.6900**	$ 0.6625	**$ 2.0700**	$ 1.9875

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 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Net income	**$ 118**	$ 184	**$ 738**	$ 510
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	**233**	616	**(14)**	763
Unrealized (losses) gains on net investment hedges (2) (3)	**(33)**	(95)	**3**	(116)
Cash flow hedges				
Net derivative gains	**-**	-	**1**	-
Less: reclassification adjustment for gains included in income	**(1)**	(1)	**(2)**	(2)
Net effects of cash flow hedges	**(1)**	(1)	**(1)**	(2)
Unrealized losses on available-for-sale investment	**-**	(1)	**-**	(1)
Net change in unrecognized pension and post-retirement benefit obligation	**1**	2	**(4)**	(6)
Other comprehensive income (loss) (4)	**$ 200**	$ 521	**$ (16)**	$ 638
Comprehensive income	**318**	705	**722**	1,148
Comprehensive income attributable to non-controlling interest	**1**	1	**1**	1
Comprehensive income of Emera Incorporated	**$ 317**	$ 704	**$ 721**	$ 1,147

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

(1) Net of tax expense of $3 million (2022 – $10 million expense) for the three months ended September 30, 2023 and tax recovery of $4 million (2022 – $10 million expense) for the nine months ended September 30, 2023.
(2) The Company has designated $1.2 billion United States dollar ("USD") denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations.
(3) Net of tax expense of nil (2022 – $2 million recovery) for the three months ended September 30, 2023 and tax expense of nil (2022 – $6 million recovery) for the nine months ended September 30, 2023.
(4) Net of tax expense of $3 million (2022 – $8 million expense) for the three months ended September 30, 2023 and tax recovery of $4 million (2022 – $4 million expense) for the nine months ended September 30, 2023.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of dollars		**September 30 2023**		December 31 2022
Assets				
Current assets				
Cash and cash equivalents	**$**	**254**	$	310
Restricted cash (note 23)		**19**		22
Inventory		**840**		769
Derivative instruments (notes 13 and 14)		**220**		296
Regulatory assets (note 6)		**391**		602
Receivables and other current assets (note 16)		**1,651**		2,897
		3,375		4,896
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $10,011 and $9,574, respectively		**24,215**		22,996
Other assets				
Deferred income taxes (note 9)		**243**		237
Derivative instruments (notes 13 and 14)		**59**		100
Regulatory assets (note 6)		**2,789**		3,018
Net investment in direct finance and sales type leases		**589**		604
Investments subject to significant influence (note 7)		**1,418**		1,418
Goodwill		**6,001**		6,012
Other long-term assets		**458**		461
		11,557		11,850
Total assets	**$**	**39,147**	$	39,742
Liabilities and Equity				
Current liabilities				
Short-term debt (note 18)	**$**	**2,666**	$	2,726
Current portion of long-term debt (note 19)		**676**		574
Accounts payable		**1,424**		2,025
Derivative instruments (notes 13 and 14)		**392**		888
Regulatory liabilities (note 6)		**225**		495
Other current liabilities		**490**		579
		5,873		7,287
Long-term liabilities				
Long-term debt (note 19)		**16,243**		15,744
Deferred income taxes (note 9)		**2,365**		2,196
Derivative instruments (notes 13 and 14)		**88**		190
Regulatory liabilities (note 6)		**1,683**		1,778
Pension and post-retirement liabilities (note 17)		**251**		281
Other long-term liabilities (note 7)		**860**		825
		21,490		21,014
Equity				
Common stock (note 10)		**7,993**		7,762
Cumulative preferred stock		**1,422**		1,422
Contributed surplus		**82**		81
Accumulated other comprehensive income ("AOCI') (note 12)		**562**		578
Retained earnings		**1,711**		1,584
Total Emera Incorporated equity		**11,770**		11,427
Non-controlling interest in subsidiaries		**14**		14
Total equity		**11,784**		11,441
Total liabilities and equity	**$**	**39,147**	$	39,742

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

"M. Jacqueline Sheppard"
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 **2023**	 2022
Operating activities		
Net income	**$ 738**	$ 510
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**794**	703
Income from equity investments, net of dividends	**(17)**	(43)
Allowance for funds used during construction ("AFUDC") – equity	**(27)**	(37)
Deferred income taxes, net	**57**	7
Net change in pension and post-retirement liabilities	**(56)**	(40)
Fuel adjustment mechanism ("FAM")	**(35)**	(185)
Net change in fair value ("FV") of derivative instruments	**(633)**	804
Net change in regulatory assets and liabilities	**387**	(471)
Net change in capitalized transportation capacity	**556**	(620)
Other operating activities, net	**49**	178
Changes in non-cash working capital (note 22)	**5**	149
Net cash provided by operating activities	**1,818**	955
Investing activities		
Additions to PP&E	**(2,063)**	(1,704)
Other investing activities	**18**	19
Net cash used in investing activities	**(2,045)**	(1,685)
Financing activities		
Change in short-term debt, net	**47**	661
Proceeds from long-term debt, net of issuance costs	**537**	772
Retirement of long-term debt	**(113)**	(359)
Net proceeds (repayments) under committed credit facilities	**93**	(82)
Issuance of common stock, net of issuance costs	**23**	256
Dividends on common stock	**(358)**	(352)
Dividends on preferred stock	**(48)**	(47)
Other financing activities	**(15)**	(5)
Net cash provided by financing activities	**166**	844
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**2**	18
Net increase (decrease) in cash, cash equivalents, and restricted cash	**(59)**	132
Cash, cash equivalents and restricted cash, beginning of period	**332**	417
Cash, cash equivalents and restricted cash, end of period	**$ 273**	$ 549
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 250**	$ 360
Short-term investments	**4**	166
Restricted cash	**19**	23
Cash, cash equivalents and restricted cash	**$ 273**	$ 549

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	Non-Controlling Interest	Total Equity
For the three months ended September 30, 2023							
Balance, June 30, 2023	**$ 7,922**	**$ 1,422**	**$ 81**	**$ 362**	**$ 1,798**	**$ 14**	**$ 11,599**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**117**	**1**	**118**
Other comprehensive income, net of tax expense of $3 million	**-**	**-**	**-**	**200**	**-**	**-**	**200**
Dividends declared on preferred stock (1)	**-**	**-**	**-**	**-**	**(16)**	**-**	**(16)**
Dividends declared on common stock ($0.6900/share)	**-**	**-**	**-**	**-**	**(188)**	**-**	**(188)**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discounts	**66**	**-**	**-**	**-**	**-**	**-**	**66**
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	**5**	**-**	**1**	**-**	**-**	**-**	**6**
Other	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Balance, September 30, 2023	**$ 7,993**	**$ 1,422**	**$ 82**	**$ 562**	**$ 1,711**	**$ 14**	**$ 11,784**
For the nine months ended September 30, 2023							
Balance, December 31, 2022	**$ 7,762**	**$ 1,422**	**$ 81**	**$ 578**	**$ 1,584**	**$ 14**	**$ 11,441**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**737**	**1**	**738**
Other comprehensive loss, net of tax recovery of $4 million	**-**	**-**	**-**	**(16)**	**-**	**-**	**(16)**
Dividends declared on preferred stock (2)	**-**	**-**	**-**	**-**	**(48)**	**-**	**(48)**
Dividends declared on common stock ($2.0700/share)	**-**	**-**	**-**	**-**	**(562)**	**-**	**(562)**
Issued under the DRIP, net of discounts	**205**	**-**	**-**	**-**	**-**	**-**	**205**
Senior management stock options exercised and ECSPP	**26**	**-**	**1**	**-**	**-**	**-**	**27**
Other	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Balance, September 30, 2023	**$ 7,993**	**$ 1,422**	**$ 82**	**$ 562**	**$ 1,711**	**$ 14**	**$ 11,784**

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

(1) Series A; $0.1364/share, Series B; $0.3955/share, Series C; $0.2951/share, Series E; $0.2813/share, Series F; $0.2626/share; Series H; $0.3063/share; Series J; $0.2656/share and Series L; $0.2875/share
(2) Series A; $0.4092/share, Series B; $1.1302/share, Series C; $0.8852/share, Series E; $0.8438/share, Series F; $0.7879/share; Series H; $0.9188/share; Series J; $0.7969/share and Series L; $0.8625/share

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

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
For the three months ended September 30, 2022							
Balance, June 30, 2022	$ 7,509	$ 1,422	$ 80	$ 142	$ 1,295	$ 14	$ 10,462
Net income of Emera Incorporated	-	-	-	-	183	1	184
Other comprehensive income, net of tax expense of $8 million	-	-	-	521	-	-	521
Dividends declared on preferred stock (1)	-	-	-	-	(16)	-	(16)
Dividends declared on common stock ($0.6625/share)	-	-	-	-	(176)	-	(176)
Issuance of common stock under the at-the-market ("ATM") program, net of after-tax issuance costs	105	-	-	-	-	-	105
Issued under the DRIP, net of discounts	54	-	-	-	-	-	54
Senior management stock options exercised and ECSPP	7	-	-	-	-	-	7
Other	-	-	-	-	(1)	(1)	(2)
Balance, September 30, 2022	$ 7,675	$ 1,422	$ 80	$ 663	$ 1,285	$ 14	$ 11,139
For the nine months ended September 30, 2022							
Balance, December 31, 2021	$ 7,242	$ 1,422	$ 79	$ 25	$ 1,348	$ 34	$ 10,150
Net income of Emera Incorporated	-	-	-	-	509	1	510
Other comprehensive income, net of tax expense of $4 million	-	-	-	638	-	-	638
Dividends declared on preferred stock (2)	-	-	-	-	(47)	-	(47)
Dividends declared on common stock ($1.9875/share)	-	-	-	-	(524)	-	(524)
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	-	-	-	-	-	(20)	(20)
Issuance of common stock under ATM program, net of after-tax issuance costs	233	-	-	-	-	-	233
Issued under the DRIP, net of discount	171	-	-	-	-	-	171
Senior management stock options exercised and ECSPP	29	-	1	-	-	-	30
Other	-	-	-	-	(1)	(1)	(2)
Balance, September 30, 2022	$ 7,675	$ 1,422	$ 80	$ 663	$ 1,285	$ 14	$ 11,139

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

(1) Series A; $0.1364/share, Series B; $0.1803/share, Series C; $0.2951/share, Series E; $0.2813/share, Series F; $0.2626/share; Series H; $0.3063/share; Series J; $0.2656/share and Series L; $0.2875/share
(2) Series A; $0.4092/share, Series B; $0.4326/share, Series C; $0.8852/share, Series E; $0.8438/share, Series F; $0.7879/share, Series H; $0.9188/share, Series J; $0.7969/share and Series L; $0.8625/share

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 2023 and 2022

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Emera Incorporated (“Emera” or the “Company”) is an energy and services company which invests in electricity generation, transmission and distribution, and gas transmission and distribution.

At September 30, 2023, 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:
    - Nova Scotia Power Inc. (“NSPI”), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia; and
    - Emera Newfoundland & Labrador Holdings Inc. (“ENL”), consisting of two transmission investments related to an 824 megawatt (“MW”) hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador developed by Nalcor Energy. ENL’s two investments are:
        - a 100 per cent investment in NSP Maritime Link Inc. (“NSPML”), which developed the Maritime Link Project, a $1.8 billion transmission project, including AFUDC; and
        - a 31 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership (“LIL”), a $3.7 billion electricity transmission project in Newfoundland and Labrador.

- Gas Utilities and Infrastructure, which includes:
    - Peoples Gas System, Inc. (“PGS”), a regulated gas distribution utility operating across Florida. Effective January 1, 2023, Peoples Gas System ceased to be a division of Tampa Electric Company and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.;
    - New Mexico Gas Company, Inc. (“NMGC”), a regulated gas distribution utility serving customers in New Mexico;
    - 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 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 interest in Maritimes & Northeast Pipeline (“M&NP”), a 1,400-kilometre pipeline, that transports natural gas throughout markets in Atlantic Canada and the northeastern United States.

- 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;
    - Grand Bahama Power Company Limited (“GBPC”), a vertically integrated regulated electric utility on Grand Bahama Island; 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.

- Emera's other reportable segment includes investments in energy-related non-regulated companies which 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 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera US Finance LP ("Emera Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
  - Block Energy LLC (previously Emera Technologies LLC), a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers;
  - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; and
  - Other investments.

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, 2022.

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, 2023.

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 the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in Emera's 2022 annual 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 due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. Certain quarters may also be impacted by weather and the number and severity of storms.

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”). ASUs issued by FASB, but which are not yet effective, were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the unaudited condensed consolidated interim financial statements.

3. DISPOSITIONS

On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Domlec for proceeds which approximated its carrying value. Domlec was included in the Company’s Other Electric reportable segment up to its date of sale. The sale did not have a material impact on earnings.

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.

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, 2023							
Operating revenues from external customers (1)	$ 1,064	$ 388	$ 263	$ 145	$ (120)	$ -	$ 1,740
Inter-segment revenues (1)	2	-	1	-	26	(29)	-
Total operating revenues	1,066	388	264	145	(94)	(29)	1,740
Regulated fuel for generation and purchased power	282	173	-	76	-	(1)	530
Regulated cost of natural gas	-	-	58	-	-	-	58
OM&G	237	92	94	31	46	(3)	497
Provincial, state and municipal taxes	83	12	20	1	1	-	117
Depreciation and amortization	143	68	36	17	2	-	266
Income from equity investments	-	29	5	1	(3)	-	32
Other income (expense), net	17	8	1	1	(37)	25	15
Interest expense, net (2)	67	43	34	5	86	-	235
Income tax expense (recovery)	43	(1)	5	-	(81)	-	(34)
Non-controlling interest in subsidiaries	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	16	-	16
Net income (loss) attributable to common shareholders	$ 228	$ 38	$ 23	$ 16	$ (204)	$ -	$ 101
For the nine months ended September 30, 2023							
Operating revenues from external customers (1)	$ 2,715	$ 1,232	$ 1,117	$ 385	$ 142	$ -	$ 5,591
Inter-segment revenues (1)	6	-	8	-	26	(40)	-
Total operating revenues	2,721	1,232	1,125	385	168	(40)	5,591
Regulated fuel for generation and purchased power	699	512	-	197	-	(7)	1,401
Regulated cost of natural gas	-	-	392	-	-	-	392
OM&G	621	283	295	93	123	(17)	1,398
Provincial, state and municipal taxes	218	34	68	3	3	-	326
Depreciation and amortization	425	206	98	50	6	-	785
Income from equity investments	-	81	16	2	4	-	103
Other income, net	53	22	7	5	4	16	107
Interest expense, net (2)	204	128	91	17	244	-	684
Income tax expense (recovery)	95	(7)	49	-	(60)	-	77
Non-controlling interest in subsidiaries	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	48	-	48
Net income (loss) attributable to common shareholders	$ 512	$ 179	$ 155	$ 31	$ (188)	$ -	$ 689
As at September 30, 2023							
Total assets	$ 21,467	$ 8,414	$ 7,671	$ 1,334	$ 1,518	$ (1,257)	$ 39,147

(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 $26 million for the three months ended September 30, 2023, and $69 million for the nine months ended September 30, 2023 between the Florida Electric Utility, 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, 2022							
Operating revenues from external customers (1)	$ 982	$ 370	$ 343	$ 136	$ 4	$ -	$ 1,835
Inter-segment revenues (1)	2	-	1	-	(9)	6	-
Total operating revenues	984	370	344	136	(5)	6	1,835
Regulated fuel for generation and purchased power	353	185	-	75	-	(1)	612
Regulated cost of natural gas	-	-	149	-	-	-	149
OM&G	161	74	94	31	40	(1)	399
Provincial, state and municipal taxes	67	11	19	-	1	-	98
Depreciation and amortization	129	65	28	14	2	-	238
Income from equity investments	-	20	6	1	5	-	32
Other income (expense), net	16	7	4	(1)	(19)	(8)	(1)
Interest expense, net (2)	49	34	21	5	75	-	184
Income tax expense (recovery)	42	(11)	10	-	(39)	-	2
Non-controlling interests	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	16	-	16
Net income (loss) attributable to common shareholders	$ 199	$ 39	$ 33	$ 10	$ (114)	$ -	$ 167
For the nine months ended September 30, 2022							
Operating revenues from external customers (1)	$ 2,471	$ 1,254	$ 1,191	$ 386	$ (72)	$ -	$ 5,230
Inter-segment revenues (1)	5	-	4	-	7	(16)	-
Total operating revenues	2,476	1,254	1,195	386	(65)	(16)	5,230
Regulated fuel for generation and purchased power	813	603	-	217	-	(3)	1,630
Regulated cost of natural gas	-	-	554	-	-	-	554
OM&G	450	249	270	93	114	(12)	1,164
Provincial, state and municipal taxes	177	32	62	2	2	-	275
Depreciation and amortization	373	192	81	46	6	-	698
Income from equity investments	-	64	15	3	10	-	92
Other income (expense), net	44	18	11	(2)	(29)	1	43
Interest expense, net (2)	127	99	57	14	206	-	503
Income tax expense (recovery)	108	(8)	48	-	(117)	-	31
Non-controlling interest in subsidiaries	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	47	-	47
Net income (loss) attributable to common shareholders	$ 472	$ 169	$ 149	$ 14	$ (342)	$ -	$ 462
As at December 31, 2022							
Total assets	$ 21,053	$ 8,223	$ 7,737	$ 1,337	$ 2,835	$ (1,443)	$ 39,742

(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 $4 million for the three months ended September 30, 2022, and $10 million for the nine months ended September 30, 2022 between the Gas Utilities and Infrastructure and Other segments.

5. REVENUE

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

	Electric			Gas	Other		
millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2023							
Regulated Revenue							
Residential	$ 761	$ 179	$ 54	$ 100	$ -	$ -	$ 1,094
Commercial	313	111	74	76	-	-	574
Industrial	76	81	9	23	-	(1)	188
Other electric	96	8	2	-	-	-	106
Regulatory deferrals	(184)	-	3	-	-	-	(181)
Other (1)	4	9	3	44	-	(2)	58
Finance income (2)(3)	-	-	-	16	-	-	16
Regulated revenue	1,066	388	145	259	-	(3)	1,855
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	-	-	-
Other non-regulated operating revenue	-	-	-	5	7	(6)	6
Mark-to-market (3)	-	-	-	-	(101)	(20)	(121)
Non-regulated revenue	-	-	-	5	(94)	(26)	(115)
Total operating revenues	**$ 1,066**	**$ 388**	**$ 145**	**$ 264**	**$ (94)**	**$ (29)**	**$ 1,740**
For the nine months ended September 30, 2023							
Regulated Revenue							
Residential	$ 1,777	$ 671	$ 136	$ 529	$ -	$ -	$ 3,113
Commercial	813	345	204	311	-	-	1,673
Industrial	205	159	25	68	-	(8)	449
Other electric	311	29	5	-	-	-	345
Regulatory deferrals	(399)	-	9	-	-	-	(390)
Other (1)	14	28	6	154	-	(6)	196
Finance income (2)(3)	-	-	-	47	-	-	47
Regulated revenue	2,721	1,232	385	1,109	-	(14)	5,433
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	61	-	61
Other non-regulated operating revenue	-	-	-	16	22	(18)	20
Mark-to-market (3)	-	-	-	-	85	(8)	77
Non-regulated revenue	-	-	-	16	168	(26)	158
Total operating revenues	**$ 2,721**	**$ 1,232**	**$ 385**	**$ 1,125**	**$ 168**	**$ (40)**	**$ 5,591**

(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	Electric Florida Electric Utility	 Canadian Electric Utilities	 Other Electric Utilities	Gas Gas Utilities and Infrastructure	Other Other	 Inter-Segment Eliminations	Total
For the three months ended September 30, 2022							
Regulated Revenue							
Residential	$ 581	$ 157	$ 49	$ 125	$ -	$ -	$ 912
Commercial	253	99	73	91	-	1	517
Industrial	60	98	10	23	-	(4)	187
Other electric	102	7	(2)	-	-	-	107
Regulatory deferrals	(15)	-	4	-	-	-	(11)
Other (1)	3	9	2	86	-	-	100
Finance income (2)(3)	-	-	-	15	-	-	15
Regulated revenue	984	370	136	340	-	(3)	1,827
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	24	-	24
Other non-regulated operating revenue	-	-	-	4	3	(3)	4
Mark-to-market (3)	-	-	-	-	(32)	12	(20)
Non-regulated revenue	-	-	-	4	(5)	9	8
Total operating revenues	$ 984	$ 370	$ 136	$ 344	$ (5)	$ 6	$ 1,835
For the nine months ended September 30, 2022							
Regulated Revenue							
Residential	$ 1,367	$ 624	$ 137	$ 541	$ -	$ -	$ 2,669
Commercial	644	318	209	323	-	-	1,494
Industrial	165	266	25	60	-	(4)	512
Other electric	309	21	5	-	-	-	335
Regulatory deferrals	(22)	-	4	-	-	-	(18)
Other (1)	13	25	6	215	-	(5)	254
Finance income (2)(3)	-	-	-	44	-	-	44
Regulated revenue	2,476	1,254	386	1,183	-	(9)	5,290
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	71	-	71
Other non-regulated operating revenue	-	-	-	12	13	(9)	16
Mark-to-market (3)	-	-	-	-	(149)	2	(147)
Non-regulated revenue	-	-	-	12	(65)	(7)	(60)
Total operating revenues	$ 2,476	$ 1,254	$ 386	$ 1,195	$ (65)	$ (16)	$ 5,230

(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, lighting contracts, and long-term steam supply arrangements with fixed contract terms. As of September 30, 2023, the aggregate amount of the transaction price allocated to remaining performance obligations was $461 million (2022 – $465 million). This amount includes $137 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040. 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 2043.

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 2022 annual audited consolidated financial statements. Updates to regulatory environments are included below.

As at millions of dollars	**September 30 2023**	December 31 2022
Regulatory assets		
Deferred income tax regulatory assets	**$ 1,225**	$ 1,166
TEC capital cost recovery for early retired assets	**674**	674
Cost recovery clauses	**284**	707
Pension and post-retirement medical plan	**371**	369
FAM	**343**	307
TEC storm reserve	**53**	103
Deferrals related to derivative instruments	**28**	30
Environmental remediations	**28**	27
Stranded cost recovery	**27**	27
GBPC storm restoration	**26**	35
NMGC winter event gas cost recovery	**24**	69
Other	**97**	106
	$ 3,180	$ 3,620
Current	**$ 391**	$ 602
Long-term	**2,789**	3,018
Total regulatory assets	**$ 3,180**	$ 3,620
Regulatory liabilities		
Accumulated reserve − cost of removal	**$ 886**	$ 895
Deferred income tax regulatory liabilities	**846**	877
Deferrals related to derivative instruments	**71**	230
Cost recovery clauses	**61**	70
BLPC Self-insurance fund ("SIF") (note 23)	**30**	30
NMGC gas hedge settlements	**-**	162
Other	**14**	9
	$ 1,908	$ 2,273
Current	**$ 225**	$ 495
Long-term	**1,683**	1,778
Total regulatory liabilities	**$ 1,908**	$ 2,273

Florida Electric Utility

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

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were $36 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings.

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

Canadian Electric Utilities

NSPI

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

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

Extra Large Industrial Active Demand Tariff:
On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment has been recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

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

Nova Scotia Cap-and-Trade Program:
As of December 31, 2022, the FAM included a cumulative $166 million in fuel costs related to the accrued purchase of emissions credits and $6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province of Nova Scotia amended the Nova Scotia Cap-and-Trade Program Regulations, providing NSPI with additional emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. Accrued compliance costs of $166 million related to the anticipated purchase of emissions credits were reversed in Q1 2023. Credits NSPI purchased from provincial auctions in the amount of $6 million will not be refunded and NSPI does not anticipate further costs related to the Nova Scotia Cap-and-Trade Program.

NSPML

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

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

NSPML did not record additional holdback in Q3 2023, which is subject to UARB confirmation and the UARB granting relief in September relating to a planned outage of the LIL.

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

Gas Utilities and Infrastructure

PGS

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

NMGC

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

Other Electric Utilities

BLPC

Clean Energy Transition Program ("CETP"):
On May 31, 2023, the Fair Trading Commission, Barbados ("FTC") approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETP (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETP.

General Rate Review Application:
On October 4, 2021, BLPC submitted a general rate review application to the FTC. On September 16, 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. On February 15, 2023, the FTC issued a decision on the BLPC rate review application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the SIF of $50 million USD and prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and a regulatory asset related to accumulated depreciation of $11 million USD. The FTC also requested a compliance filing before setting final rates which was submitted by BLPC on March 8, 2023. On March 7, 2023, BLPC filed a Motion for Review and Variation of FTC's decision and applied for a Stay of the Decision. The FTC determined that it would hear the Motion for Review by way of an oral hearing and parties were invited to submit and exchange written submissions on these matters during Q2 2023. On May 12, 2023, the FTC granted the Stay of the Decision until the determination of the Motion for Review and Variation. The Motion was heard in August 2023 and BLPC is awaiting FTC's decision. BLPC expects a final order from the FTC in Q4 2023.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

	Carrying Value as at		Equity Income (loss) for three months ended September 30		Equity Income for the nine months ended September 30		Percentage of Ownership
millions of dollars	**September 30 2023**	December 31 2022	**2023**	2022	**2023**	2022	**2023**
LIL (1)	**$ 750**	$ 740	**$ 16**	$ 15	**$ 47**	$ 43	31.0
NSPML	**497**	501	**13**	5	**34**	21	100.0
M&NP (2)	**122**	128	**5**	6	**16**	15	12.9
Lucelec (2)	**49**	49	**1**	1	**2**	3	19.5
Bear Swamp (3)	**-**	-	**(3)**	5	**4**	10	50.0
	$ 1,418	$ 1,418	**$ 32**	$ 32	**$ 103**	$ 92	

(1) Emera indirectly owns 100 per cent of the LIL Class B units, which comprises 24.5 per cent of the total units issued. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.
(2) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method.
(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 $91 million (2022 – $95 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 2023**	December 31 2022
Current assets	**$ 46**	$ 17
PP&E	**1,486**	1,517
Regulatory assets	**268**	265
Non-current assets	**29**	29
Total assets	**$ 1,829**	$ 1,828
Current liabilities	**$ 59**	$ 48
Long-term debt (1)	**1,129**	1,149
Non-current liabilities	**144**	130
Equity	**497**	501
Total liabilities and equity	**$ 1,829**	$ 1,828

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

8. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of dollars	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Interest on debt	**$ 244**	$ 189	**$ 706**	$ 514
Allowance for borrowed funds used during construction	**(4)**	(6)	**(11)**	(15)
Other	**(5)**	1	**(11)**	4
	$ 235	$ 184	**$ 684**	$ 503

9. INCOME TAXES

The income tax provision differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

For the millions of dollars	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Income before provision for income taxes	**$ 84**	$ 186	**$ 815**	$ 541
Statutory income tax rate	**29%**	29%	**29%**	29%
Income taxes, at statutory income tax rate	**24**	54	**236**	157
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(8)**	(20)	**(53)**	(55)
Foreign tax rate variance	**(14)**	(14)	**(33)**	(30)
Amortization of deferred income tax regulatory liabilities	**(16)**	(14)	**(32)**	(27)
Tax credits	**(15)**	(3)	**(32)**	(7)
Tax effect of equity earnings	**(4)**	(2)	**(11)**	(7)
Other	**(1)**	1	**2**	-
Income tax (recovery) expense	**$ (34)**	$ 2	**$ 77**	$ 31
Effective income tax rate	**(40%)**	1%	**9%**	6%

On August 16, 2022, the United States Inflation Reduction Act (“IRA”) was signed into legislation. The IRA includes numerous tax incentives for clean energy, such as the extension and modification of existing investment and production tax credits for projects placed in service through 2024 and introduces new technology-neutral clean energy related tax credits beginning in 2025. As of September 30, 2023, the Company has recorded a $26 million regulatory liability in recognition of its obligation to pass the incremental tax benefits realized to customers.

10. COMMON STOCK

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

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

ATM Equity Program

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

11. EARNINGS PER SHARE

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

For the millions of dollars (except per share amounts)	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Numerator				
Net income attributable to common shareholders	**$ 100.6**	$ 167.1	**$ 688.5**	$ 461.6
Diluted numerator	**100.6**	167.1	**688.5**	461.6
Denominator				
Weighted average shares of common stock outstanding – basic	**273.6**	266.6	**272.2**	264.3
Stock-based compensation	**0.2**	0.4	**0.3**	0.5
Weighted average shares of common stock outstanding – diluted	**273.8**	267.0	**272.5**	264.8
Earnings per common share				
Basic	**$ 0.37**	$ 0.63	**$ 2.53**	$ 1.75
Diluted	**$ 0.37**	$ 0.63	**$ 2.53**	$ 1.74

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

millions of dollars	Unrealized gain (loss) 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, 2023						
Balance, January 1, 2023	**$ 639**	**$ (62)**	**$ 16**	**$ (2)**	**$ (13)**	**$ 578**
Other comprehensive (loss) income before reclassifications	**(14)**	**3**	**1**	**-**	**-**	**(10)**
Amounts reclassified from AOCI	**-**	**-**	**(2)**	**-**	**(4)**	**(6)**
Net current period other comprehensive (loss) income	**(14)**	**3**	**(1)**	**-**	**(4)**	**(16)**
Balance, September 30, 2023	**$ 625**	**$ (59)**	**$ 15**	**$ (2)**	**$ (17)**	**$ 562**
For the nine months ended September 30, 2022						
Balance, January 1, 2022	$ 10	$ 35	$ 18	$ (1)	$ (37)	$ 25
Other comprehensive income (loss) before reclassifications	763	(116)	-	(1)	-	646
Amounts reclassified from AOCI	-	-	(2)	-	(6)	(8)
Net current period other comprehensive income (loss)	763	(116)	(2)	(1)	(6)	638
Balance, September 30, 2022	$ 773	$ (81)	$ 16	$ (2)	$ (43)	$ 663

The reclassifications out of AOCI are as follows:

For the millions of dollars	Affected line item in the Condensed Consolidated Interim Financial Statements	Three months ended September 30 **2023**	2022	Nine months ended September 30 **2023**	2022
		Amounts reclassified from AOCI			
Gain on derivatives recognized as cash flow hedges					
Interest rate hedge	Interest expense, net	**$ (1)**	$ (1)	**$ (2)**	$ (2)
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses	Other income, net	**$ -**	$ 2	**$ -**	$ 6
Amounts reclassified into obligations	Pension and post-retirement benefits	**1**	-	**(4)**	(12)
Total		**1**	2	**(4)**	(6)
Total reclassifications out of AOCI, for the period		**$ -**	$ 1	**$ (6)**	$ (8)

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, NMGC and GBPC 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. TEC and PGS have no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases which ends on December 31, 2024.

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 2023**	December 31 2022	**September 30 2023**	December 31 2022
Regulatory deferral:				
Commodity swaps and forwards	**$ 88**	$ 186	**$ 39**	$ 42
FX forwards	**10**	18	**-**	1
Physical natural gas purchases	**1**	52	**-**	-
	99	256	**39**	43
HFT derivatives:				
Power swaps and physical contracts	**35**	89	**33**	77
Natural gas swaps, futures, forwards, physical contracts	**332**	340	**567**	1,224
	367	429	**600**	1,301
Other derivatives:				
Equity derivatives	**-**	-	**17**	5
FX forwards	**7**	5	**18**	23
	7	5	**35**	28
Total gross derivatives	**473**	690	**674**	1,372
Impact of master netting agreements:				
Regulatory deferral	**(13)**	(18)	**(13)**	(18)
HFT derivatives	**(181)**	(276)	**(181)**	(276)
Total impact of master netting agreements	**(194)**	(294)	**(194)**	(294)
Total derivatives	**$ 279**	$ 396	**$ 480**	$ 1,078
Current (1)	**220**	296	**392**	888
Long-term (1)	**59**	100	**88**	190
Total derivatives	**$ 279**	$ 396	**$ 480**	$ 1,078

(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. The Company has FX forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

The amounts related to cash flow hedges recorded in AOCI consisted of the following:

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

For the three and nine months ended September 30, 2023, unrealized gains of $1 million (2022 – $1 million) and $2 million (2022 – $2 million) respectively, have been reclassified from AOCI into interest expense. The Company expects $3 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months.

As at September 30, 2023, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2023
FX forwards (USD) sales	$ 13

Regulatory Deferral

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

millions of dollars	**Physical natural gas purchases**	**Commodity swaps and forwards**	**FX forwards**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the three months ended September 30			**2023**			2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ 11**	**$ 4**	$ -	$ (30)	$ 1
Unrealized gain in regulatory liabilities	**-**	**12**	**6**	8	92	15
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	19	-
Realized gain in regulatory liabilities	**-**	**(1)**	**-**	-	(12)	-
Realized (gain) loss in inventory (1)	**-**	**2**	**(1)**	-	(42)	-
Realized gain in regulated fuel for generation and purchased power (2)	**(6)**	**-**	**-**	(5)	(45)	(1)
Total change in derivative	**$ (6)**	**$ 19**	**$ 9**	$ 3	$ (18)	$ 15
For the nine months ended September 30			**2023**			2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (18)**	**$ 1**	$ -	$ (68)	$ 2
Unrealized gain (loss) in regulatory liabilities	**(3)**	**(47)**	**4**	47	421	17
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	35	-
Realized (gain) loss in regulatory liabilities	**-**	**3**	**-**	-	(34)	-
Realized (gain) loss in inventory (1)	**-**	**7**	**(10)**	-	(84)	4
Realized gain in regulated fuel for generation and purchased power (2)	**(48)**	**(20)**	**(2)**	(39)	(103)	-
Other	**-**	**(15)**	**-**	-	-	-
Total change in derivative	**$ (51)**	**$ (95)**	**$ (7)**	$ 8	$ 167	$ 23

(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, 2023, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2023	2024-2026
Physical natural gas purchases:		
Natural gas (MMBtu)	1	-
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	8	30
Power (MWh)	1	2
Coal (metric tonnes)	-	1
FX swaps and forwards:		
FX contracts (millions of USD)	$ 72	$ 261
Weighted average rate	1.3347	1.3136
% of USD requirements	98%	33%

HFT Derivatives

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

For the millions of dollars	Three months ended September 30 **2023**	Three months ended September 30 2022	Nine months ended September 30 **2023**	Nine months ended September 30 2022
Power swaps and physical contracts in non-regulated operating revenues	**$ (2)**	$ 5	**$ (2)**	$ 9
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**92**	(572)	**909**	(644)
Total gains (losses) in net income	**$ 90**	$ (567)	**$ 907**	$ (635)

As at September 30, 2023, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2023	2024	2025	2026	2027 and thereafter
Natural gas purchases (MMBtu)	114	230	60	45	38
Natural gas sales (MMBtu)	190	384	151	16	12
Power purchases (MWh)	1	1	-	-	-
Power sales (MWh)	1	1	-	-	-

Other Derivatives

As at September 30, 2023, the Company had equity derivatives in place to manage the 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 2.8 million shares and extends until December 2023. The FX forwards have a combined notional amount of $559 million USD and expire in 2023 through 2025.

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		**2023**		2022
Unrealized loss in OM&G	**$ -**	**$ (20)**	$ -	$ (12)
Unrealized loss in other income, net	**(16)**	**-**	(31)	-
Realized loss in other income, net	**(2)**	**-**	(1)	-
Total losses in net income	**$ (18)**	**$ (20)**	$ (32)	$ (12)
For the nine months ended September 30		**2023**		2022
Unrealized loss in OM&G	**$ -**	**$ (12)**	$ -	$ (21)
Unrealized gain (loss) in other income, net	**7**	**-**	(30)	-
Realized loss in other income, net	**(7)**	**-**	(1)	-
Total losses in net income	**$ -**	**$ (12)**	$ (31)	$ (21)

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 internally assesses credit risk 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, 2023, the Company had $160 million (December 31, 2022 – $131 million) in financial assets considered to be past due, which had been outstanding for an average 58 days. The FV of these financial assets was $142 million (December 31, 2022 – $114 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** **2023**	December 31 2022
Cash collateral provided to others	**$ 38**	$ 224
Cash collateral received from others	**$ 10**	$ 112

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, 2023, the total FV of derivatives in a liability position was $480 million (December 31, 2022 – $1,078 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, 2023 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 30	$ 45	$ -	$ 75
FX forwards	-	10	-	10
Physical natural gas purchases	-	-	1	1
	30	55	1	86
HFT derivatives:				
Power swaps and physical contracts	1	27	-	28
Natural gas swaps, futures, forwards, physical contracts and related transportation	14	116	28	158
	15	143	28	186
Other derivatives:				
FX forwards	-	7	-	7
	-	7	-	7
Total assets	45	205	29	279
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	22	4	-	26
	22	4	-	26
HFT derivatives:				
Power swaps and physical contracts	1	27	-	28
Natural gas swaps, futures, forwards and physical contracts	4	36	351	391
	5	63	351	419
Other derivatives:				
FX forwards	-	18	-	18
Equity derivatives	17	-	-	17
	17	18	-	35
Total liabilities	44	85	351	480
Net assets (liabilities)	$ 1	$ 120	$ (322)	$ (201)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 120	$ 48	$ -	$ 168
FX forwards	-	18	-	18
Physical natural gas purchases and sales	-	-	52	52
	120	66	52	238
HFT derivatives:				
Power swaps and physical contracts	9	31	4	44
Natural gas swaps, futures, forwards, physical contracts and related transportation	3	72	34	109
	12	103	38	153
Other derivatives:				
FX forwards	-	5	-	5
Total assets	132	174	90	396
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	9	-	24
FX forwards	-	1	-	1
	15	10	-	25
HFT derivatives:				
Power swaps and physical contracts	2	28	1	31
Natural gas swaps, futures, forwards and physical contracts	51	118	825	994
	53	146	826	1,025
Other derivatives:				
FX forwards	-	23	-	23
Equity derivatives	5	-	-	5
	5	23	-	28
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

The change in the FV of the Level 3 financial assets for the three months ended September 30, 2023 was as follows:

	Regulatory Deferral	*HFT Derivatives*		
millions of dollars	Physical natural gas purchases	Power	Natural gas	Total
Balance, beginning of period	$ 7	$ -	$ 25	$ 32
Realized gains included in fuel for generation and purchased power	(6)	-	-	(6)
Total realized and unrealized gains included in non-regulated operating revenues	-	-	3	3
Balance, September 30, 2023	**$ 1**	**$ -**	**$ 28**	**$ 29**

The change in the FV of the Level 3 financial liabilities for the three months ended September 30, 2023 was as follows:

	HFT Derivatives		
millions of dollars	Power	Natural gas	Total
Balance, beginning of period	$ 1	$ 356	$ 357
Total realized and unrealized gains included in non-regulated operating revenues	(1)	(5)	(6)
Balance, September 30, 2023	**$ -**	**$ 351**	**$ 351**

The change in the FV of the Level 3 financial assets for the nine months ended September 30, 2023 was as follows:

	Regulatory Deferral	*HFT Derivatives*		
millions of dollars	Physical natural gas purchases	Power	Natural gas	Total
Balance, beginning of period	$ 52	$ 4	$ 34	$ 90
Realized gains included in fuel for generation and purchased power	(48)	-	-	(48)
Unrealized losses included in regulatory liabilities	(3)	-	-	(3)
Total realized and unrealized losses included in non-regulated operating revenues	-	(4)	(6)	(10)
Balance, September 30, 2023	**$ 1**	**$ -**	**$ 28**	**$ 29**

The change in the FV of the Level 3 financial liabilities for the nine months ended September 30, 2023 was as follows:

	HFT Derivatives		
millions of dollars	Power	Natural gas	Total
Balance, beginning of period	$ 1	$ 825	$ 826
Total realized and unrealized gains included in non-regulated operating revenues	(1)	(474)	(475)
Balance, September 30, 2023	**$ -**	**$ 351**	**$ 351**

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:

					September 30, 2023
As at **millions of dollars**	**FV**		**Significant Unobservable Input**	**Low**	**High**	**Weighted Average (1)**
	Assets	**Liabilities**				
Regulatory deferral – Physical natural gas purchases	**$ 1**	**$ -**	Third-party pricing	$3.61	$3.61	$3.61
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**28**	**351**	Third-party pricing	$1.17	$17.85	$6.83
Total	**$ 29**	**$ 351**				
Net liability		**$ 322**				

(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, 2023	**$ 16,919**	**$ 14,761**	**$ 146**	**$ 14,368**	**$ 247**	**$ 14,761**
December 31, 2022	$ 16,318	$ 14,670	$ -	$ 14,284	$ 386	$ 14,670

The Company has designated $1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. An after-tax foreign currency loss of $33 million was recorded in AOCI for the three months ended September 30, 2023 (2022 – $95 million after-tax loss) and an after-tax foreign currency gain of $3 million was recorded for the nine months ended September 30, 2023 (2022 – $116 million after-tax loss).

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 $44 million for the three months ended September 30, 2023 (2022 – $41 million) and $122 million for the nine months ended September 30, 2023 (2022 – $118 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments.

- Natural gas transportation capacity purchases from M&NP are reported in the Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues – non-regulated, totalled $2 million for the three months ended September 30, 2023 (2022 – $1 million) and $10 million for the nine months ended September 30, 2023 (2022 – $7 million).

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

16. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars	**September 30 2023**	December 31 2022
Customer accounts receivable – billed	**$ 817**	$ 1,096
Capitalized transportation capacity (1)	**258**	781
Customer accounts receivable – unbilled	**312**	424
Prepaid expenses	**134**	82
Income tax receivable	**13**	9
Allowance for credit losses	**(18)**	(17)
NMGC gas hedge settlement receivable (2)	**-**	162
Other	**135**	360
Total receivables and other current assets	**$ 1,651**	$ 2,897

(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.
(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the purchased gas adjustment clause. Refer to note 7 in Emera's 2022 annual audited consolidated financial statements.

17. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, New Mexico, Barbados, and Grand Bahama Island.

Emera's net periodic benefit cost included the following:

For the millions of dollars	Three months ended September 30 **2023**	 2022	Nine months ended September 30 **2023**	 2022
Defined benefit pension plans				
Service cost	**$ 8**	$ 10	**$ 23**	**$** 31
Non-service cost:				
Interest cost	**27**	20	**83**	60
Expected return on plan assets	**(40)**	(36)	**(121)**	(108)
Current year amortization of:				
Actuarial losses	**-**	2	**-**	6
Regulatory asset	**2**	5	**5**	15
Settlements and curtailments	**2**	1	**2**	1
Total non-service costs	**(9)**	(8)	**(31)**	(26)
Total defined benefit pension plans	**(1)**	2	**(8)**	5
Non-pension benefit plans				
Service cost	**1**	1	**2**	3
Non-service cost:				
Interest cost	**3**	3	**10**	7
Expected return on plan assets	**-**	(1)	**(1)**	(1)
Current year amortization of:				
Actuarial gains	**(1)**	-	**(1)**	-
Regulatory asset	**(1)**	1	**(3)**	2
Total non-service costs	**1**	3	**5**	8
Total non-pension benefit plans	**2**	4	**7**	11
Total defined benefit plans	**$ 1**	$ 6	**$ (1)**	$ 16

Emera's pension and non-pension contributions related to these defined-benefit plans for the three months ended September 30, 2023 were $20 million (2022 – $24 million), and for the nine months ended September 30, 2023 were $55 million (2022 – $55 million). Annual employer contributions to the defined benefit pension plans are estimated to be $44 million for 2023. Emera's contributions related to these defined contribution plans for the three months ended September 30, 2023 were $11 million (2022 – $11 million) and $33 million (2022 – $30 million) for the nine months ended September 30, 2023.

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 23 in Emera's 2022 annual audited consolidated financial statements, and below for 2023 short-term debt financing activity.

Florida Electric Utilities

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representation and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

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

Other

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

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

19. LONG-TERM DEBT

For details regarding long-term debt, refer to note 25 in Emera's 2022 annual audited consolidated financial statements, and below for 2023 long-term debt financing activity.

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053.

Gas Utilities and Infrastructure

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

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028.

Other

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030.

20. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2023, 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	2023	2024	2025	2026	2027	Thereafter	Total
Transportation (1)	$ 199	$ 642	$ 498	$ 414	$ 398	$ 2,999	$ 5,150
Purchased power (2)	74	260	241	257	306	3,591	4,729
Fuel, gas supply and storage	314	590	218	65	5	1	1,193
Capital projects	655	234	25	5	-	-	919
Equity investment commitments (3)	-	240	-	-	-	-	240
Other	37	152	141	55	47	218	650
	$ 1,279	$ 2,118	$ 1,123	$ 796	$ 756	$ 6,809	$ 12,881

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $137 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(2) Annual requirement to purchase electricity production from Independent Power Producers or other utilities over varying contract lengths.
(3) Emera has a commitment to make equity contributions to the LIL. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be made in 2024.

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

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

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

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, 2023, the aggregate financial liability of the Florida utilities is estimated to be $17 million ($13 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 Condensed 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 the 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 the remediation work. However, in those instances that they are not, the Florida utilities could be liable for more than their actual percentage of the remediation costs. Other factors that could impact these estimates include additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the 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 27 in Emera's 2022 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, 2023.

D. Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2022 audited annual consolidated financial statements, with material updates as noted below:

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

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

21. CUMULATIVE PREFERRED STOCK

For details regarding cumulative preferred stock, refer to note 28 in Emera's 2022 annual audited consolidated financial statements, and below for 2023 preferred stock activity.

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

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

22. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the	Nine months ended September 30			
millions of dollars		**2023**		2022
Changes in non-cash working capital:				
Inventory	**$**	**(71)**	$	(162)
Receivables and other current assets (1)		**731**		(259)
Accounts payable		**(541)**		471
Other current liabilities (2)		**(114)**		99
Total non-cash working capital	**$**	**5**	$	149

1) The nine months ended September 30, 2023, includes $162 million related to the January 2023 settlement of NMGC gas hedges. Offsetting change in regulatory liabilities is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
2) The nine months ended September 30, 2023, includes $(166) million related to the decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the	Nine months ended September 30			
millions of dollars		**2023**		2022
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**205**	$	172
Increase in accrued capital expenditures	**$**	**45**	$	(8)
Reclassification of long-term debt to short-term debt	**$**	**-**	$	500
Reclassification of short-term debt and current portion of long-term debt to long-term debt	**$**	**135**	$	-
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**54**	$	(459)

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 in NSPML. When the critical milestones were achieved, Nalcor Energy 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 NSPML. Thus, Emera records NSPML 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 in "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 must 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, 2023**		December 31, 2022	
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)	**$ 497**	**$ 6**	$ 501	$ 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 10, 2023, the date the unaudited condensed consolidated interim financial statements were issued.