EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2022 and 2021

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of dollars (except per share amounts)	Three months ended September 30 **2022**	2021	Nine months ended September 30 **2022**	2021
Operating revenues				
Regulated electric	**$ 1,489**	$ 1,244	**$ 4,111**	$ 3,445
Regulated gas	**338**	237	**1,179**	874
Non-regulated	**8**	(333)	**(60)**	(422)
Total operating revenues (note 5)	**1,835**	1,148	**5,230**	3,897
Operating expenses				
Regulated fuel for generation and purchased power	**612**	476	**1,630**	1,263
Regulated cost of natural gas	**149**	71	**554**	297
Operating, maintenance and general expenses ("OM&G")	**399**	341	**1,164**	1,002
Provincial, state and municipal taxes	**98**	85	**275**	246
Depreciation and amortization	**238**	228	**698**	675
Total operating expenses	**1,496**	1,201	**4,321**	3,483
Income (loss) from operations	**339**	(53)	**909**	414
Income from equity investments (note 7)	**32**	33	**92**	111
Other income (expense), net	**(1)**	22	**43**	67
Interest expense, net	**184**	150	**503**	460
Income (loss) before provision for income taxes	**186**	(148)	**541**	132
Income tax expense (recovery) (note 8)	**2**	(92)	**31**	(91)
Net income (loss)	**184**	(56)	**510**	223
Non-controlling interest in subsidiaries	**1**	-	**1**	1
Preferred stock dividends	**16**	14	**47**	36
Net income (loss) attributable to common shareholders	**$ 167**	$ (70)	**$ 462**	$ 186
Weighted average shares of common stock outstanding (in millions) (note 10)				
Basic	**266.6**	258.5	**264.3**	256.0
Diluted	**267.0**	258.5	**264.8**	256.4
Earnings (loss) per common share (note 10)				
Basic	**$ 0.63**	$ (0.27)	**$ 1.75**	$ 0.73
Diluted	**$ 0.63**	$ (0.27)	**$ 1.74**	$ 0.73
Dividends per common share declared	**$ 0.6625**	$ 0.6375	**$ 1.9875**	$ 1.9125

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 2022	2021	Nine months ended September 30 2022	2021
Net income (loss)	**$ 184**	$ (56)	**$ 510**	$ 223
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	**616**	243	**763**	(1)
Unrealized losses on net investment hedges (2) (3)	**(95)**	(35)	**(116)**	(1)
Cash flow hedges				
Net derivative gains (4)	**-**	-	**-**	18
Less: reclassification adjustment for gains included in income	**(1)**	(1)	**(2)**	(1)
Net effects of cash flow hedges	**(1)**	(1)	**(2)**	17
Unrealized losses on available-for-sale investment	**(1)**	-	**(1)**	-
Net change in unrecognized pension and post-retirement benefit obligation	**2**	4	**(6)**	13
Other comprehensive income (5)	**521**	211	**638**	28
Comprehensive income	**705**	155	**1,148**	251
Comprehensive income attributable to non-controlling interest	**1**	-	**1**	1
Comprehensive income of Emera Incorporated	**$ 704**	$ 155	**$ 1,147**	$ 250

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

(1) Net of tax expense of $10 million (2021 - nil) for the three months ended September 30, 2022 and tax expense of $10 million (2021 – $5 million expense) for the nine months ended September 30, 2022.
(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 recovery of $2 million (2021 - $6 million recovery) for the three months ended September 30, 2022 and tax recovery of $6 million (2021 – nil) for the nine months ended September 30, 2022.
(4) Net of tax expense of nil (2021 - nil) for the three months ended September 30, 2022 and tax expense of nil (2021 – $6 million expense) for the nine months ended September 30, 2022.
(5) Net of tax expense of $8 million (2021 - $6 million recovery) for the three months ended September 30, 2022 and tax expense of $4 million (2021 – $11 million expense) for the nine months ended September 30, 2022.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of dollars		September 30 2022		December 31 2021
Assets				
Current assets				
Cash and cash equivalents	**$**	**526**	$	394
Restricted cash (note 22)		**23**		23
Inventory		**722**		538
Derivative instruments (notes 12 and 13)		**554**		195
Regulatory assets (note 6)		**846**		253
Receivables and other current assets (note 15)		**2,679**		1,733
		5,350		3,136
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $9,548 and $8,739, respectively		**22,555**		20,353
Other assets				
Deferred income taxes (note 8)		**361**		295
Derivative instruments (notes 12 and 13)		**143**		106
Regulatory assets (note 6)		**2,585**		2,313
Net investment in direct finance and sales type leases (note 16)		**604**		503
Investments subject to significant influence (note 7)		**1,418**		1,382
Goodwill		**6,158**		5,696
Other long-term assets		**630**		460
		11,899		10,755
Total assets	**$**	**39,804**	$	34,244
Liabilities and Equity				
Current liabilities				
Short-term debt (note 18)	**$**	**2,514**	$	1,742
Current portion of long-term debt (note 19)		**575**		462
Accounts payable		**2,071**		1,485
Derivative instruments (notes 12 and 13)		**1,545**		533
Regulatory liabilities (note 6)		**488**		290
Other current liabilities		**497**		366
		7,690		4,878
Long-term liabilities				
Long-term debt (note 19)		**15,285**		14,196
Deferred income taxes (note 8)		**2,054**		1,868
Derivative instruments (notes 12 and 13)		**256**		149
Regulatory liabilities (note 6)		**1,884**		1,765
Pension and post-retirement liabilities (note 17)		**367**		370
Other long-term liabilities (note 7)		**1,129**		868
		20,975		19,216
Equity				
Common stock (note 9)		**7,675**		7,242
Cumulative preferred stock		**1,422**		1,422
Contributed surplus		**80**		79
Accumulated other comprehensive income ("AOCI') (note 11)		**663**		25
Retained earnings		**1,285**		1,348
Total Emera Incorporated equity		**11,125**		10,116
Non-controlling interest in subsidiaries		**14**		34
Total equity		**11,139**		10,150
Total liabilities and equity	**$**	**39,804**	$	34,244

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 **2022**	 2021
Operating activities		
Net income	**$ 510**	$ 223
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**703**	682
Income from equity investments, net of dividends	**(43)**	(56)
Allowance for equity funds used during construction	**(37)**	(44)
Deferred income taxes, net	**7**	(111)
Net change in pension and post-retirement liabilities	**(40)**	(25)
Regulated fuel adjustment mechanism	**(185)**	(71)
Net change in fair value of derivative instruments	**804**	416
Net change in regulatory assets and liabilities	**(471)**	(124)
Net change in capitalized transportation capacity	**(620)**	96
Other operating activities, net	**178**	49
Changes in non-cash working capital (note 21)	**149**	71
Net cash provided by operating activities	**955**	1,106
Investing activities		
Additions to PP&E	**(1,704)**	(1,596)
Other investing activities	**19**	20
Net cash used in investing activities	**(1,685)**	(1,576)
Financing activities		
Change in short-term debt, net	**661**	88
Repayment of short-term debt with maturities greater than 90 days	**-**	(377)
Proceeds from long-term debt, net of issuance costs	**772**	2,329
Retirement of long-term debt	**(359)**	(1,541)
Net repayments under committed credit facilities	**(82)**	(87)
Issuance of common stock, net of issuance costs	**256**	236
Issuance of preferred stock, net of issuance costs	**-**	416
Dividends on common stock	**(352)**	(329)
Dividends on preferred stock	**(47)**	(36)
Other financing activities	**(5)**	(6)
Net cash provided by financing activities	**844**	693
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**18**	(1)
Net increase in cash, cash equivalents, and restricted cash	**132**	222
Cash, cash equivalents and restricted cash, beginning of period	**417**	254
Cash, cash equivalents and restricted cash, end of period	**$ 549**	$ 476
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 360**	$ 198
Short-term investments	**166**	242
Restricted cash	**23**	36
Cash, cash equivalents and restricted cash	**$ 549**	$ 476

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, 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 ($0.6625/share)	**-**	**-**	**-**	**-**	**(176)**	**-**	**(176)**
Issued under the Dividend Reinvestment Program, net of discounts	**54**	**-**	**-**	**-**	**-**	**-**	**54**
Issuance of common stock under the at-the-market ("ATM") program, net of after-tax issuance costs	**105**	**-**	**-**	**-**	**-**	**-**	**105**
Senior management stock options exercised and Employee Share Purchase Plan	**7**	**-**	**-**	**-**	**-**	**-**	**7**
Other	**-**	**-**	**-**	**-**	**(1)**	**(1)**	**(2)**
Balance, September 30, 2022	**$ 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 ($1.9875/share)	**-**	**-**	**-**	**-**	**(524)**	**-**	**(524)**
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	**-**	**-**	**-**	**-**	**-**	**(20)**	**(20)**
Issued under the Dividend Reinvestment Program, net of discounts	**171**	**-**	**-**	**-**	**-**	**-**	**171**
Issuance of common stock under ATM program, net of after-tax issuance costs	**233**	**-**	**-**	**-**	**-**	**-**	**233**
Senior management stock options exercised and Employee Share Purchase Plan	**29**	**-**	**1**	**-**	**-**	**-**	**30**
Other	**-**	**-**	**-**	**-**	**(1)**	**(1)**	**(2)**
Balance, September 30, 2022	**$ 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; $0.29506/share, Series E; $0.28125/share, Series F; $0.26263/share; Series H; $0.30625/share; Series J; $0.265625/share and Series L; $0.2875/share
(2) Series A; $0.4092/share, Series B; $0.4326/share, Series C; $0.88518/share, Series E; $0.84375/share, Series F; $0.78789/share; Series H; $0.91875/share; Series J; $0.79688/share and Series L; $0.86250/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, 2021							
Balance, June 30, 2021	$ 6,957	$ 1,200	$ 79	$ (262)	$ 1,431	$ 34	$ 9,439
Net loss of Emera Incorporated	-	-	-	-	(56)	-	(56)
Other comprehensive income, net of tax recovery of $6 million	-	-	-	211	-	-	211
Dividends declared on preferred stock (1)	-	-	-	-	(14)	-	(14)
Dividends declared on common stock ($0.6375/share)	-	-	-	-	(164)	-	(164)
Issuance of preferred stock, net of after-tax issuance costs	-	222	-	-	-	-	222
Issued under the Dividend Reinvestment Program, net of discounts	55	-	-	-	-	-	55
Issuance of common stock under ATM program, net of after-tax issuance costs	83	-	-	-	-	-	83
Senior management stock options exercised and Employee Share Purchas Plan	8	-	-	-	-	-	8
Other	-	-	-	-	-	-	-
Balance, September 30, 2021	$ 7,103	$ 1,422	$ 79	$ (51)	$ 1,197	$ 34	$ 9,784
For the nine months ended September 30, 2021							
Balance, December 31, 2020	$ 6,705	$ 1,004	$ 79	$ (79)	$ 1,495	$ 34	$ 9,238
Net income of Emera Incorporated	-	-	-	-	222	1	223
Other comprehensive income, net of tax expense of $11 million	-	-	-	28	-	-	28
Dividends declared on preferred stock (2)	-	-	-	-	(36)	-	(36)
Dividends declared on common stock ($1.9125/share)	-	-	-	-	(486)	-	(486)
Issuance of preferred stock, net of after-tax issuance costs	-	418	-	-	-	-	418
Issued under the Dividend Reinvestment Program, net of discounts	174	-	-	-	-	-	174
Issuance of common stock under ATM program, net of after-tax issuance costs	211	-	-	-	-	-	211
Senior management stock option exercised and Employee Share Purchase Plan	10	-	-	-	-	-	10
Other	3	-	-	-	2	(1)	4
Balance, September 30, 2021	$ 7,103	$ 1,422	$ 79	$ (51)	$ 1,197	$ 34	$ 9,784

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

(1) Series A; $0.1364/share, Series B; $0.1222/share, Series C; $0.29506/share, Series E; $0.28125/share, Series F; $0.26263/share; Series H; $0.30625/share and Series J; $0.38134/share
(2) Series A; $0.4092/share, Series B; $0.3613/share, Series C; $0.88518/share, Series E; $0.84375/share, Series F; $0.78789/share; Series H; $0.91875/share and Series J; $0.38134/share

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 2022 and 2021

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, 2022, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, 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 being 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 (including AFUDC) transmission project; and
        - a 34.7 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 ("PGS"), a regulated gas distribution utility operating across Florida;
    - 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 Canada, 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 Reinsurance Limited, a captive insurance company providing insurance and reinsurance to Emera and certain affiliates;
    - Emera US Finance LP ("Emera Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
    - 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.

The outbreak of COVID-19 in 2020 resulted in governments worldwide enacting emergency measures to combat the spread of the virus. Management considered the impact of COVID-19 on the Company's estimates and results, and concluded the unaudited condensed consolidated interim financial statements as at and for the three and nine months ended September 30, 2022, were not materially impacted.

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, 2021.

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, 2022.

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

Use of Management Estimates

The preparation of unaudited condensed consolidated interim financial statements 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 the 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 2021 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, 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 interest in subsidiaries	-	-	-	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 September 30, 2022							
Total assets	$ 20,966	$ 8,168	$ 7,390	$ 1,414	$ 3,329	$ (1,463)	$ 39,804

(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 in Q3 2022 and $10 million year-to-date between the Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2021							
Operating revenues from external customers (1)	$ 796	$ 328	$ 241	$ 120	$ (337)	$ -	$ 1,148
Inter-segment revenues (1)	2	-	1	-	7	(10)	-
Total operating revenues	798	328	242	120	(330)	(10)	1,148
Regulated fuel for generation and purchased power	274	144	-	59	-	(1)	476
Regulated cost of natural gas	-	-	71	-	-	-	71
OM&G	133	72	79	37	27	(7)	341
Provincial, state and municipal	58	11	16	-	-	-	85
Depreciation and amortization	120	61	31	14	2	-	228
Income from equity investments	-	25	5	1	2	-	33
Other income, net	16	4	3	3	(6)	2	22
Interest expense, net (2)	34	32	15	6	63	-	150
Income tax expense (recovery)	26	(5)	9	-	(122)	-	(92)
Preferred stock dividends	-	-	-	-	14	-	14
Net income (loss) attributable to common shareholders	$ 169	$ 42	$ 29	$ 8	$ (318)	$ -	$ (70)
For the nine months ended September 30, 2021							
Operating revenues from external customers (1)	$ 2,012	$ 1,112	$ 886	$ 321	$ (434)	$ -	$ 3,897
Inter-segment revenues (1)	5	-	3	-	21	(29)	-
Total operating revenues	2,017	1,112	889	321	(413)	(29)	3,897
Regulated fuel for generation and purchased power	628	484	-	154	-	(3)	1,263
Regulated cost of natural gas	-	-	297	-	-	-	297
OM&G	381	222	238	98	83	(20)	1,002
Provincial, state and municipal	158	32	53	3	-	-	246
Depreciation and amortization	351	184	90	44	6	-	675
Income from equity investments	-	78	15	3	15	-	111
Other income, net	42	9	8	7	(5)	6	67
Interest expense, net (2)	105	100	48	16	191	-	460
Income tax expense (recovery)	59	3	43	1	(197)	-	(91)
Non-controlling interest in subsidiaries	-	-	-	1	-	-	1
Preferred stock dividends	-	-	-	-	36	-	36
Net income (loss) attributable to common shareholders	$ 377	$ 174	$ 143	$ 14	$ (522)	$ -	$ 186
As at December 31, 2021							
Total assets	$ 17,903	$ 7,418	$ 6,666	$ 1,402	$ 2,034	$ (1,179)	$ 34,244

(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 $3 million in Q3 2021 and $10 million year-to-date in 2021 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, 2022							
Regulated Revenue							
Residential	$ 581	$ 157	$ 49	$ 125	$ -	$ -	$ 912
Commercial	253	99	73	91	-	1	517
Industrial	60	98	10	23	-	(4)	187
Other regulatory deferrals	87	7	2	-	-	-	96
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 regulatory deferrals	287	21	9	-	-	-	317
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 Canada.
(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, 2021							
Regulated Revenue							
Residential	$ 454	$ 154	$ 44	$ 102	$ -	$ -	$ 754
Commercial	214	97	64	76	-	-	451
Industrial	58	61	8	16	-	-	143
Other regulatory deferrals	70	7	2	-	-	-	79
Other (1)	2	9	2	29	-	(3)	39
Finance income (2)(3)	-	-	-	15	-	-	15
Regulated revenue	798	328	120	238	-	(3)	1,481
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	(4)	-	(4)
Other non-regulated operating revenue	-	-	-	4	8	(4)	8
Mark-to-market (3)	-	-	-	-	(334)	(3)	(337)
Non-regulated revenue	-	-	-	4	(330)	(7)	(333)
Total operating revenues	$ 798	$ 328	$ 120	$ 242	$ (330)	$ (10)	$ 1,148
For the nine months ended September 30, 2021							
Regulated Revenue							
Residential	$ 1,086	$ 588	$ 121	$ 430	$ -	$ -	$ 2,225
Commercial	550	303	166	268	-	-	1,287
Industrial	156	176	21	48	-	(1)	400
Other regulatory deferrals	214	21	5	-	-	-	240
Other (1)	11	24	8	88	-	(7)	124
Finance income (2)(3)	-	-	-	43	-	-	43
Regulated revenue	2,017	1,112	321	877	-	(8)	4,319
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	63	-	63
Other non-regulated operating revenue	-	-	-	12	25	(15)	22
Mark-to-market (3)	-	-	-	-	(501)	(6)	(507)
Non-regulated revenue	-	-	-	12	(413)	(21)	(422)
Total operating revenues	$ 2,017	$ 1,112	$ 321	$ 889	$ (413)	$ (29)	$ 3,897

(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 Canada.
(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, 2022, the aggregate amount of the transaction price allocated to remaining performance obligations was $465 million (2021 – $435 million). This amount includes $147 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 2042.

6. REGULATORY ASSETS AND LIABILITIES

A summary of the Company's 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 2021 annual audited consolidated financial statements.

As at millions of dollars		**September 30 2022**		December 31 2021
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,147**	$	1,045
Tampa Electric capital cost recovery for early retired assets		**688**		657
Cost recovery clauses		**605**		114
Regulated fuel adjustment mechanism ("FAM")		**330**		145
Pension and post-retirement medical plan		**296**		291
NMGC winter event gas cost recovery		**83**		117
Deferrals related to derivative instruments		**61**		23
Storm restoration regulatory asset		**38**		35
Environmental remediations		**30**		27
Storm reserve		**29**		-
Stranded cost recovery		**28**		26
Other		**96**		86
	$	**3,431**	$	2,566
Current	**$**	**846**	$	253
Long-term		**2,585**		2,313
Total regulatory assets	**$**	**3,431**	$	2,566
Regulatory liabilities				
Deferred income tax regulatory liabilities	**$**	**911**	$	863
Accumulated reserve - cost of removal		**888**		819
Deferrals related to derivative instruments		**448**		241
Cost recovery clauses		**74**		35
Self-insurance fund (note 22)		**30**		28
Storm reserve		**1**		58
Other		**20**		11
	$	**2,372**	$	2,055
Current	**$**	**488**	$	290
Long-term		**1,884**		1,765
Total regulatory liabilities	**$**	**2,372**	$	2,055

Tampa Electric

Storm Reserve
In September 2022, Tampa Electric was impacted by Hurricane Ian. The majority of Hurricane Ian restoration costs will be charged against Tampa Electric's Florida Public Service Commission ("FPSC") approved storm reserve, resulting in minimal impact on earnings for 2022. The total cost of restoration is estimated to be $130 million USD. As of September 30, 2022, Tampa Electric incurred $68 million USD in storm restoration cost and an additional $62 million USD in storm restoration costs are expected to be incurred in Q4 2022. Total restoration costs charged to the storm reserve have exceeded the reserve balance and have been deferred as a regulatory asset for future recovery. Tampa Electric expects to petition the FPSC in late 2022 or early 2023 for recovery of the storm reserve regulatory asset and the replenishment of the balance in the reserve to the previous approved reserve level of $56 million USD, for a total of approximately $136 million USD.

Storm Protection Plan ("SPP") Cost Recovery Clause
On April 11, 2022, Tampa Electric filed a new SPP with the FPSC to determine the storm hardening activities and related costs in 2023, 2024 and 2025. On October 4, 2022, the FPSC approved Tampa Electric's SPP.

ROE Adjustment
Tampa Electric's 2021 settlement agreement allows the company to request an increase to revenue and ROE due to increases in the 30-year United States Treasury bond yield rate. On July 1, 2022, Tampa Electric requested the FPSC to increase its annual base rates by $10 million USD effective September 1, 2022 and to increase its ROE. On August 16, 2022, the FPSC approved the change. Effective July 1, 2022, the new mid-point ROE is 10.20 per cent, and the range is 9.25 per cent to 11.25 per cent.

Mid-Course Fuel Adjustment
The mid-course fuel adjustment requested by Tampa Electric on January 19, 2022, was approved on March 1, 2022. The rate increase, effective with the first billing cycle in April 2022, covered higher fuel and capacity costs of $169 million USD and will be spread over customer bills from April 1, 2022 through December 2022.

NSPI

General Rate Application
On January 27, 2022, NSPI filed a General Rate Application ("GRA") with the Nova Scotia Utility and Review Board ("UARB"), which was then amended on February 18, 2022. The GRA proposes a rate stability plan for 2022 through 2024 which includes average rate increases of 2.8 per cent per year on August 1, 2022, January 1, 2023 and January 1, 2024 to recover non-fuel costs. On September 2, 2022, NSPI filed a fuel update to the GRA proposing that the cost of fuel increases be smoothed over 2023 and 2024 and the forecast FAM balance at December 31, 2022 be recovered over three years (2023 through 2025), resulting in combined fuel rate increases of 1.6 per cent on January 1, 2023 and January 1, 2024 to recover fuel costs. The remaining recovery of the 2022 FAM balance is forecast to be collected in 2025 and would require an additional fuel rate increase of 1.3 per cent subject to UARB approval in future rate applications. The effective timing of any approved increases would be determined by the UARB. The hearing for this matter concluded in September 2022 with closing submissions to be filed in Q4 2022. A decision by the UARB is expected in Q1 2023.

On November 9, 2022, the Nova Scotia provincial government enacted Bill 212, "Public Utilities Act (amended)". The legislation pre-empts the pending UARB GRA decision and limits non-fuel rate increases, excluding increases relating to demand-side management costs, to a total of 1.8 per cent between the effective date of the UARB's decision and the end of 2024. The legislation also:

- requires revenue generated from the non-fuel rate increase to be used only to improve the reliability of service to ratepayers;
- limits NSPI's return on equity to 9.25 per cent and equity ratio to 40 per cent; and
- limits the rate used to accrue interest on regulatory deferrals to the Bank of Canada policy interest rate plus 1.75 per cent, unless otherwise directed by the UARB.

Nova Scotia Cap-and-Trade Program
As at September 30, 2022, the FAM includes a recovery of $190 million (December 31, 2021 – $38 million) non-cash accrual representing the estimated future cost of acquiring emissions credits for the 2019 through 2022 Nova Scotia Cap-and-Trade compliance period. These costs are estimated based on forecast emissions for the compliance period and are sensitive to changes to forecasts of energy received from Muskrat Falls for the remainder of 2022 and the actual emissions profile. Each 1 per cent change in forecasted emissions for the balance of the compliance period would result in a $2 million change in the expense and liability, which NSPI anticipates being recoverable through the FAM.

Lower than forecasted Muskrat Falls energy received during the compliance period has resulted in the increased deployment of higher carbon-emitting generation sources. The Province of Nova Scotia has announced that it will provide $165 million of relief from the 2019 through 2022 compliance costs, which was equal to the total cost of compliance forecasted at the time of the September 2022 GRA fuel update. Discussions related to how this relief will be provided are ongoing and have not been reflected in the accrued compliance costs recognized to date.

NSPML

On August 3, 2022, NSPML submitted an application to the UARB requesting recovery of approximately $164 million in Maritime Link costs for 2023. A decision is expected in Q4 2022.

PGS

In September 2022, Hurricane Ian impacted PGS's operations in Fort Myers and Sarasota. The estimated restoration costs are expected to be up to $3 million USD and will be charged against PGS's FPSC approved storm reserve, resulting in minimal impact to earnings.

NMGC

On December 13, 2021, NMGC filed a rate case with the New Mexico Public Regulation Commission ("NMPRC") for new rates to become effective January 2023. On May 20, 2022, NMGC filed an unopposed settlement agreement with the NMPRC for an increase of $19 million USD in annual base revenues. The proposed rates reflect the recovery of increased operating costs and capital investments in pipelines and related infrastructure. A hearing was held in June 2022 and a decision from the NMPRC is expected in Q4 2022.

BLPC

On October 4, 2021 BLPC submitted a general rate review application to the Fair Trading Commission ("FTC"). The application seeks a rate adjustment and the implementation of a cost reflective rate structure that will facilitate the changes expected in the newly reformed electricity market and the country's transition towards 100 per cent renewable energy generation. The application seeks recovery of capital investment in plant, equipment and related infrastructure and results in an increase in annual non-fuel revenue of approximately $23 million USD upon approval. The application includes a request for an allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. On September 16, 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of $3 million USD for the remainder of 2022. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. The hearing concluded in October 2022 and BLPC expects a decision on final rates from the FTC in 2022.

GBPC

Effective November 1, 2022, GBPC's fuel pass through charge was increased due to an increase in global oil prices impacting the unhedged fuel cost. In 2023 the fuel pass through charge will be adjusted monthly in-line with actual fuel costs.

On January 14, 2022, The Grand Bahama Port Authority issued its decision on GBPC's rate application. The approved increase in annual revenues of $3.5 million USD commenced on April 1, 2022.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value as at September 30 **2022**	December 31 2021	Equity Income for the three months ended September 30 **2022**	2021	Equity Income for the nine months ended September 30 **2022**	2021	Percentage of Ownership **2022**
LIL (1)	**$ 725**	$ 682	**$ 15**	$ 13	**$ 43**	$ 39	34.7
NSPML	**514**	533	**5**	12	**21**	39	100.0
M&NP (2)	**129**	123	**6**	5	**15**	15	12.9
Lucelec (2)	**50**	44	**1**	1	**3**	3	19.5
Bear Swamp (3)	**-**	-	**5**	2	**10**	15	50.0
	$ 1,418	$ 1,382	**$ 32**	$ 33	**$ 92**	$ 111	

(1) Emera indirectly owns 100 per cent of the LIL Class B units, which comprises 24.9 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 $104 million (2021 – $105 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 22). NSPML's consolidated summarized balance sheet is as follows:

As at millions of dollars	**September 30 2022**	December 31 2021
Current assets	**$ 44**	$ 25
PP&E	**1,533**	1,587
Regulatory assets	**263**	247
Non-current assets	**30**	31
Total assets	**$ 1,870**	$ 1,890
Current liabilities	**$ 60**	$ 50
Long-term debt (1)	**1,169**	1,189
Non-current liabilities	**127**	118
Equity	**514**	533
Total liabilities and equity	**$ 1,870**	$ 1,890

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

8. 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 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Income (loss) before provision for income taxes	**$ 186**	$ (148)	**$ 541**	$ 132
Statutory income tax rate	**29.0%**	29.0%	**29.0%**	29.0%
Income taxes, at statutory income tax rate	**54**	(43)	**157**	38
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(20)**	(16)	**(55)**	(47)
Foreign tax rate variance	**(14)**	(11)	**(30)**	(27)
Amortization of deferred income tax regulatory liabilities	**(14)**	(12)	**(27)**	(28)
Tax effect of equity earnings	**(2)**	(3)	**(7)**	(12)
Tax credits	**(3)**	(3)	**(7)**	(10)
Manufacturing allowance	**(1)**	(2)	**(4)**	(5)
Other	**2**	(2)	**4**	-
Income tax (recovery) expense	**$ 2**	$ (92)	**$ 31**	$ (91)
Effective income tax rate	**1%**	62%	**6%**	(69%)

On August 16, 2022, the United States Inflation Reduction Act was signed into legislation and includes numerous tax incentives for clean energy, including solar, as well as several revenue raising provisions. Emera is evaluating the impact of the new legislation and does not expect a material impact on the consolidated financial statements.

During 2022, the Canada Revenue Agency ("CRA") issued notices of reassessment to NSPI for the 2013 through 2016 taxation years. NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $126 million (2021 - $62 million), including interest. NSPI has prepaid $55 million (2021 - $23 million) of the amount in dispute, as required by the CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

Should NSPI be similarly reassessed by the CRA for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Notice of Appeal process is not determinable at this time.

9. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of dollars	
Balance, December 31, 2021	261.07	$	7,242
Issuance of common stock under ATM program (1)	3.79		233
Issued under the Dividend Reinvestment Program, net of discounts	2.86		171
Senior management stock options exercised and Employee Share Purchase Plan	0.51		29
Balance, September 30, 2022	**268.23**	**$**	**7,675**

(1) In Q3 2022, 1,715,056 common shares were issued under Emera's ATM program at an average price of $61.87 per share for gross proceeds of $106 million ($105 million net of after-tax issuance costs). For the nine months ended September 30, 2022, 3,793,924 common shares were issued under Emera's ATM program at an average price of $61.85 per share for gross proceeds of $235 million ($233 million net of after-tax issuance costs). As at September 30, 2022, an aggregate gross sales limit of $222 million remained available for issuance under the ATM program.

10. 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 **2022**	2021	Nine months ended September 30 **2022**	2021
Numerator				
Net income (loss) attributable to common shareholders	**$ 167.1**	$ (70.0)	**$ 461.6**	$ 186.4
Diluted numerator	**167.1**	(70.0)	**461.6**	186.4
Denominator				
Weighted average shares of common stock outstanding	**266.6**	257.3	**264.3**	254.7
Weighted average deferred share units outstanding (1)	**-**	1.2	**-**	1.3
Weighted average shares of common stock outstanding – basic	**266.6**	258.5	**264.3**	256.0
Stock-based compensation (2)	**0.4**	-	**0.5**	0.4
Weighted average shares of common stock outstanding – diluted	**267.0**	258.5	**264.8**	256.4
Earnings (loss) per common share				
Basic	**$ 0.63**	$ (0.27)	**$ 1.75**	$ 0.73
Diluted	**$ 0.63**	$ (0.27)	**$ 1.74**	$ 0.73

(1) Effective February 10, 2022, deferred share units are no longer able to be settled in shares and are therefore no longer included in the calculation of earnings per common share.
(2) The potential common shares from 0.5 million related to stock-based compensation were excluded from diluted EPS for the three months ended September 30, 2021, as the Company had net loss in this quarter.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

millions of dollars		Unrealized (loss) gain on translation of self-sustaining foreign operations		Net change in net investment hedges		(Losses) gains 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, 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**
For the nine months ended September 30, 2021												
Balance, January 1, 2021	$	52	$	30	$	1	$	(1)	$	(161)	$	(79)
Other comprehensive income (loss) before reclassifications		(1)		(1)		18		-		-		16
Amounts reclassified from AOCI		-		-		(1)		-		13		12
Net current period other comprehensive income (loss)		(1)		(1)		17		-		13		28
Balance, September 30, 2021	$	51	$	29	$	18	$	(1)	$	(148)	$	(51)

The reclassifications out of AOCI are as follows:

For the		Three months ended September 30				Nine months ended September 30			
millions of dollars			**2022**		2021		**2022**		2021
Affected line item in the Consolidated Interim Financial Statements		Amounts reclassified from AOCI							
Gain on derivatives recognized as cash flow hedges									
Interest rate hedge	Interest expense, net	**$**	**(1)**	$	(1)	**$**	**(2)**	$	(1)
Total		**$**	**(1)**	$	(1)	**$**	**(2)**	$	(1)
Net change in unrecognized pension and post-retirement benefit costs									
Actuarial losses	Other income, net	**$**	**2**	$	4	**$**	**6**	$	13
Amounts reclassified into obligations	Pension and post-retirement liabilities		**-**		-		**(12)**		-
Total			**2**		4		**(6)**		13
Total reclassifications out of AOCI, for the period		**$**	**1**	$	3	**$**	**(8)**	$	12

12. 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 the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value 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 fair value of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized.

   Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value with any changes in fair value 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 fair value on the balance sheet as derivative assets or liabilities. The change in fair value 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. Tampa Electric 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, 2022.

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 fair value, 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 2022**	December 31 2021	**September 30 2022**	December 31 2021
Regulatory deferral:				
Commodity swaps and forwards	**$ 355**	$ 146	**$ 58**	$ 16
FX forwards	**22**	7	**-**	8
Physical natural gas purchases	**96**	88	**-**	-
	473	241	**58**	24
HFT derivatives:				
Power swaps and physical contracts	**186**	33	**177**	32
Natural gas swaps, futures, forwards, physical contracts	**493**	208	**1,981**	818
	679	241	**2,158**	850
Other derivatives:				
Equity derivatives	**-**	11	**10**	-
FX forwards	**5**	-	**35**	-
	5	11	**45**	-
Total gross current derivatives	**1,157**	493	**2,261**	874
Impact of master netting agreements:				
Regulatory deferral	**(26)**	(4)	**(26)**	(4)
HFT derivatives	**(434)**	(188)	**(434)**	(188)
Total impact of master netting agreements	**(460)**	(192)	**(460)**	(192)
Total derivatives	**$** 697	$ 301	**$** 1,801	$ 682
Current (1)	**554**	195	**1,545**	533
Long-term (1)	**143**	106	**256**	149
Total derivatives	**$ 697**	$ 301	**$ 1,801**	$ 682

(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 the treasury lock was settled for a gain of $19 million USD that will be amortized through interest expense over 10 years. As of September 30, 2022, the unrealized gain in AOCI was $16 million, net of tax (2021 - $18 million, net of tax). For the three and nine months ended September 30, 2022, unrealized gains of $1 million (2021 - $1 million) and $2 million (2021 - $1 million), respectively, have been reclassified into interest expense. The company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months, as the underlying hedged item settles. As of September 30, 2022, there were no outstanding cash flow hedges.

Regulatory Deferral

The Company has recorded the following changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

millions of dollars	**Physical natural gas purchases**	**Commodity swaps and forwards**	**Foreign exchange forwards**	Physical natural gas purchases	Commodity swaps and forwards	Foreign exchange forwards
For the three months ended September 30			**2022**			2021
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (30)**	**$ 1**	$ -	$ 10	$ 11
Unrealized gain in regulatory liabilities	**8**	**92**	**15**	-	177	3
Realized (gain) loss in regulatory assets	**-**	**19**	**-**	-	(1)	-
Realized (gain) loss in regulatory liabilities	**-**	**(12)**	**-**	-	1	-
Realized loss in inventory (1)	**-**	**(42)**	**-**	-	(4)	-
Realized gain in regulated fuel for generation and purchased power (2)	**(5)**	**(45)**	**(1)**	-	(13)	-
Total change in derivative instruments	**$ 3**	**$ (18)**	**$ 15**	$ -	$ 170	$ 14

millions of dollars	**Physical natural gas purchases**	**Commodity swaps and forwards**	**Foreign exchange forwards**	Physical natural gas purchases	Commodity swaps and forwards	Foreign exchange forwards
For the nine months ended September 30			**2022**			2021
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (68)**	**$ 2**	$ -	$ 21	$ 8
Unrealized gain (loss) in regulatory liabilities	**47**	**421**	**17**	-	264	(1)
Realized (gain) loss in regulatory assets	**-**	**35**	**-**	-	(3)	-
Realized gain in regulatory liabilities	**-**	**(34)**	**-**	-	(1)	-
Realized (gain) loss in inventory (1)	**-**	**(84)**	**4**	-	2	3
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(39)**	**(103)**	**-**	-	(13)	4
Total change in derivative instruments	**$ 8**	**$ 167**	**$ 23**	$ -	$ 270	$ 14

(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; hedging relationships that have been terminated or the hedged transaction is no longer probable.

As at September 30, 2022, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2022	2023-2025
Physical natural gas purchases:		
Natural gas (Mmbtu)	2	6
Commodity swaps and forwards purchases:		
Natural gas (Mmbtu)	10	28
Heavy fuel oil (Bbls)	-	1
Power (MWh)	-	3
FX swaps and forwards:		
FX contracts (millions of USD)	$ 31	$ 190
Weighted average rate	1.2487	1.2533
% of USD requirements	50%	23%

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 **2022**	2021	Nine months ended September 30 **2022**	2021
Power swaps and physical contracts in non-regulated operating revenues	**$ 5**	$ 1	**$ 9**	$ 3
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(572)**	(236)	**(644)**	(229)
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**-**	-	**-**	1
Total losses in net income	**$ (567)**	$ (235)	**$ (635)**	$ (225)

As at September 30, 2022, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2022	2023	2024	2025	2026 and thereafter
Natural gas purchases (Mmbtu)	129	254	85	38	166
Natural gas sales (Mmbtu)	205	420	181	101	12
Power purchases (MWh)	1	2	-	-	-
Power sales (MWh)	1	2	-	-	-

Other Derivatives

As at September 30, 2022, 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 2022. The FX forwards have a combined notional amount of $477 million USD and expire throughout 2022, 2023, and 2024.

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

millions of dollars	**Foreign exchange forwards**	**Equity derivatives**	Foreign exchange forwards	Equity derivatives
For the three months ended September 30		**2022**		2021
Unrealized gain (loss) in OM&G	**$ -**	**$ (12)**	$ -	$ 3
Unrealized loss in other income, net	**(31)**	**-**	(5)	-
Realized gain (loss) in other income, net	**(1)**	**-**	4	-
Total gains (losses) in net income	**$ (32)**	**$ (12)**	$ (1)	$ 3

millions of dollars	**Foreign exchange forwards**	**Equity derivatives**	Foreign exchange forwards	Equity derivatives
For the nine months ended September 30		**2022**		2021
Unrealized gain (loss) in OM&G	**$ -**	**$ (21)**	$ -	$ 9
Unrealized loss in other income, net	**(30)**	**-**	(11)	-
Realized gain (loss) in other income, net	**(1)**	**-**	13	-
Total gains (losses) in net income	**$ (31)**	**$ (21)**	$ 2	$ 9

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, 2022, the Company had $140 million (December 31, 2021 - $114 million) in financial assets considered to be past due, which had been outstanding for an average 59 days. The fair value of these financial assets was $119 million (December 31, 2021 - $93 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 2022**	December 31 2021
Cash collateral provided to others	**$ 306**	$ 212
Cash collateral received from others	**$ 249**	$ 100

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, 2022, the total fair value of derivatives in a liability position was $1,801 million (December 31, 2021 – $682 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.

13. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 12), and uses a market approach to do so. The three levels of the fair value 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 fair value measurement.

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

As at millions of dollars	Level 1	Level 2	Level 3	September 30, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 221	$ 108	$ -	$ 329
FX forwards	-	22	-	22
Physical natural gas purchases	-	-	96	96
	221	130	96	447
HFT derivatives:				
Power swaps and physical contracts	4	74	10	88
Natural gas swaps, futures, forwards, physical contracts and related transportation	(12)	97	72	157
	(8)	171	82	245
Other derivatives:				
FX forwards	-	5	-	5
Total assets	213	306	178	697
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	14	18	-	32
HFT derivatives:				
Power swaps and physical contracts	6	69	4	79
Natural gas swaps, futures, forwards and physical contracts	61	234	1,350	1,645
	67	303	1,354	1,724
Other derivatives:				
FX forwards	-	35	-	35
Equity derivatives	10	-	-	10
	10	35	-	45
Total liabilities	91	356	1,354	1,801
Net assets (liabilities)	$ 122	$ (50)	$ (1,176)	$ (1,104)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2021 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 101	$ 41	$ -	$ 142
FX forwards	-	7	-	7
Physical natural gas purchases and sales	-	-	88	88
	101	48	88	237
HFT derivatives:				
Power swaps and physical contracts	4	5	4	13
Natural gas swaps, futures, forwards, physical contracts and related transportation	(1)	29	12	40
	3	34	16	53
Other derivatives:				
Equity derivatives	11	-	-	11
Total assets	115	82	104	301
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	7	5	-	12
FX forwards	-	8	-	8
	7	13	-	20
HFT derivatives:				
Power swaps and physical contracts	4	5	3	12
Natural gas swaps, futures, forwards and physical contracts	13	122	515	650
	17	127	518	662
Total liabilities	24	140	518	682
Net assets (liabilities)	$ 91	$ (58)	$ (414)	$ (381)

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2022 was as follows:

	Regulatory Deferral	*HFT Derivatives*		
millions of dollars	Physical natural gas purchases	Power	Natural gas	Total
Balance, beginning of period	$ 93	$ 8	$ 59	$ 160
Realized gain included in fuel for generation and purchased power	(5)	-	-	(5)
Unrealized gains included in regulatory liabilities	8	-	-	8
Total realized and unrealized gains included in non-regulated operating revenues	-	2	13	15
Balance, September 30, 2022	**$ 96**	**$ 10**	**$ 72**	**$ 178**

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2022 was as follows:

	HFT Derivatives		
millions of dollars	Power	Natural gas	Total
Balance, beginning of period	$ 5	$ 691	$ 696
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(1)	659	658
Balance, September 30, 2022	**$ 4**	**$ 1,350**	**$ 1,354**

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2022 was as follows:

millions of dollars	*Regulatory Deferral* Physical natural gas purchases	*HFT Derivatives* Power	*HFT Derivatives* Natural gas	Total
Balance, beginning of period	$ 88	$ 4	$ 12	$ 104
Realized gains included in fuel for generation and purchased power	(39)	-	-	(39)
Unrealized gains included in regulatory assets	47	-	-	47
Total realized and unrealized gains included in non-regulated operating revenues	-	6	60	66
Balance, September 30, 2022	**$ 96**	**$ 10**	**$ 72**	**$ 178**

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2022 was as follows:

millions of dollars	*HFT Derivatives* Power	*HFT Derivatives* Natural gas	Total
Balance, beginning of period	$ 3	$ 515	$ 518
Total realized and unrealized gains included in non-regulated operating revenues	1	835	836
Balance, September 30, 2022	**$ 4**	**$ 1,350**	**$ 1,354**

Significant unobservable inputs used in the fair value 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) fair value 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 fair value of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at						**September 30, 2022**
millions of dollars	**Fair Value**		**Significant Unobservable Input**	**Low**	**High**	**Weighted average (1)**
	Assets	**Liabilities**				
Regulatory deferral – Physical natural gas purchases	**$ 96**	**$ -**	Third-party pricing	$6.74	$48.31	$17.38
HFT derivatives – Power swaps and physical contracts	**10**	**4**	Third-party pricing	$453.48	$286.25	$249.33
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**72**	**1,350**	Third-party pricing	$2.61	$35.81	$21.41
Total	**$ 178**	**$ 1,354**				
Net liability		**$ 1,176**				

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

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

As at millions of dollars		Carrying Amount		Fair Value		Level 1		Level 2		Level 3		Total
September 30, 2022	**$**	**15,860**	**$**	**14,343**	**$**	**-**	**$**	**13,892**	**$**	**451**	**$**	**14,343**
December 31, 2021	$	14,658	$	16,775	$	-	$	16,308	$	467	$	16,775

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 $95 million was recorded in AOCI for the three months ended September 30, 2022 (2021 – $35 million after-tax loss) and an after-tax foreign currency loss of $116 million for the nine months ended September 30, 2022 (2021 – $1 million after tax loss).

14. 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 $41 million for the three months ended September 30, 2022 (2021 - $27 million) and $118 million for the nine months ended September 30, 2022 (2021 - $91 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 $1 million for the three months ended September 30, 2022 (2021 - $4 million) and $7 million for the nine months ended September 30, 2022 (2021 - $14 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, 2022 and at December 31, 2021.

15. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of dollars		**September 30 2022**		December 31 2021
Customer accounts receivable – billed	**$**	**924**	$	767
Customer accounts receivable – unbilled		**322**		318
Allowance for credit losses		**(21)**		(21)
Capitalized transportation capacity (1)		**923**		316
Income tax receivable		**12**		8
Prepaid expenses		**106**		65
Other		**413**		280
Total receivables and other current assets	**$**	**2,679**	$	1,733

(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.

16. LEASES

Lessor

The Company's net investment in direct finance and sales-type leases primarily relates to Brunswick Pipeline, Seacoast, compressed natural gas ("CNG") stations and heat pumps.

Commencing in January 2022, the Company leased a Seacoast pipeline, a 21-mile, 30-inch lateral that is classified as a sales-type lease. The term of the pipeline lateral lease is 34 years with a net investment of $100 million USD. The lessee of the new pipeline lateral has renewal options for an additional 16 years. These renewal options have not been included as part of the pipeline lateral lease term as it is not reasonably certain that they will be exercised.

For further information on the Brunswick Pipeline lease, CNG stations and heat pumps, refer to note 19 in Emera's 2021 annual audited consolidated financial statements.

The total net investment in direct finance and sales-type leases consist of the following:

As at millions of dollars		**September 30 2022**		December 31 2021
Total minimum lease payment to be received	**$**	**1,418**	$	947
Less: amounts representing estimated executory costs		**(209)**		(165)
Minimum lease payments receivable	**$**	**1,209**	$	782
Estimated residual value of leased property (unguaranteed)		**182**		183
Less: unearned finance lease income		**(753)**		(443)
Net investment in direct finance and sales-type leases	**$**	**638**	$	522
Principal due within one year (included in "Receivables and other current assets")		**34**		19
Net Investment in direct finance and sales type leases - long-term	**$**	**604**	$	503

As at September 30, 2022, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of dollars		2022		2023		2024		2025		2026		Thereafter		Total
Minimum lease payments to be received	$	23	$	93	$	93	$	94	$	93	$	1,022	$	1,418
Less: executory costs														(209)
Total													$	1,209

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 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Defined benefit pension plans				
Service cost	**$ 10**	$ 10	**$ 31**	$ 32
Non-service cost:				
Interest cost	**20**	16	**60**	50
Expected return on plan assets	**(36)**	(33)	**(108)**	(99)
Current year amortization of:				
Actuarial losses	**2**	4	**6**	13
Regulatory asset	**5**	8	**15**	21
Settlements and curtailments	**1**	-	**1**	-
Total non-service costs	**(8)**	(5)	**(26)**	(15)
Total defined benefit pension plans	**2**	5	**5**	17
Non-pension benefit plans				
Service cost	**1**	1	**3**	4
Non-service cost:				
Interest cost	**3**	2	**7**	6
Expected return on plan assets	**(1)**	(1)	**(1)**	(2)
Current year amortization of regulatory asset	**1**	2	**2**	4
Total non-service costs	**3**	3	**8**	8
Total non-pension benefit plans	**4**	4	**11**	12
Total defined benefit plans	**$ 6**	$ 9	**$ 16**	$ 29

Emera's pension and non-pension contributions related to these defined-benefit plans for the three months ended September 30, 2022 were $24 million (2021 – $24 million), and for the nine months ended September 30, 2022 were $55 million (2021 – $53 million). Annual employer contributions to the defined benefit pension plans are estimated to be $41 million for 2022. Emera's contributions related to these defined contribution plans for the three months ended September 30, 2022 were $11 million (2021 – $10 million) and $30 million (2021 – $29 million) for the nine months ended September 30, 2022.

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 2021 annual audited consolidated financial statements, and below for 2022 short-term debt financing activity.

Recent Significant Financing Activity by Segment:

Other

On August 2, 2022, Emera entered into a $400 million non-revolving term facility which matures on August 2, 2023. 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.

19. LONG-TERM DEBT

For details regarding long-term debt, refer to note 25 in Emera's 2021 annual audited consolidated financial statements, and below for 2022 long-term debt financing activity.

Recent Significant Financing Activity by Segment:

Florida Electric Utilities

On September 15, 2022, TEC repaid a $250 million USD note upon maturity. The note was repaid using existing credit facilities.

On July 12, 2022, TEC completed an issuance of $600 million USD senior notes. The issuance included $300 million USD senior notes that bear an interest rate of 3.875 per cent with a maturity date of July 12, 2024, and $300 million USD senior notes that bear an interest rate of 5 per cent with a maturity date of July 15, 2052. Proceeds from the issuance were used to repay TEC's $470 million USD commercial paper, due in 2022.

Canadian Electric Utilities

On July 15, 2022, NSPI entered into a $400 million non-revolving term facility which matures on July 15, 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.

Gas Utilities and Infrastructure

On September 23, 2022, NMGC amended its $80 million USD, unsecured, non-revolving credit facility to extend the maturity from September 23, 2022, to March 22, 2024. There were no other significant changes in commercial terms from the prior agreement.

On June 30, 2022, Brunswick Pipeline amended its credit agreement to extend the maturity from June 30, 2025 to June 30, 2026. There were no other changes in commercial terms from the prior agreement.

Other Electric Utilities

On March 25, 2022, ECI amended its amortizing floating rate notes to extend the maturity from March 25, 2022 to March 25, 2027. There were no other changes in commercial terms from the prior agreement.

20. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2022, 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	2022	2023	2024	2025	2026	Thereafter	Total
Transportation (1)	$ 183	616	475	396	364	2,917	$ 4,951
Purchased power (2)	77	268	247	242	232	2,394	3,460
Fuel, gas supply and storage	487	991	305	170	37	-	1,990
Capital projects	399	253	88	4	1	-	745
Equity investment commitments (3)	-	240	-	-	-	-	240
Other	45	81	81	60	44	223	534
	$ 1,191	$ 2,449	$ 1,196	$ 872	$ 678	$ 5,534	$ 11,920

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $147 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 upon its commissioning.

NSPI has a contractual obligation to pay NSPML for the 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 and the approval to collect $168 million from NSPI for the recovery of Maritime Link costs in 2022. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Once LIL has been commissioned, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties relating to the Maritime Link and LIL.

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, the date the NS Block delivery obligation commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

B. Legal Proceedings

TECO Guatemala Holdings ("TGH")

Prior to Emera's acquisition of TECO Energy in 2016, TGH, a wholly owned subsidiary of TECO Energy, divested of its indirect investment in the Guatemala electricity sector, but retained certain claims against the Republic of Guatemala ("Guatemala"). In 2013, TGH asserted an arbitration claim against Guatemala with the International Centre for the Settlement of Investment Disputes ("ICSID") under the Dominican Republic Central America – United States Free Trade Agreement. The arbitration concerned TGH's allegation that Guatemala unfairly set the distribution tariff for a local distribution company which harmed TGH's investment in that company. A tribunal established by the ICSID ruled in favour of TGH (the "First Award") and in November 2020, Guatemala made a payment of approximately $38 million USD in full and final satisfaction of the First Award.

On September 23, 2016, TGH had filed a request for resubmission to arbitration seeking damages in addition to those awarded in the First Award. On May 13, 2020, an ICSID tribunal awarded TGH additional damages and costs against Guatemala of more than $35 million USD plus interest (the "Second Award"). TGH subsequently requested a reconsideration of the interest quantum awarded in connection with this Second Award. On October 16, 2020, the tribunal granted TGH's request for additional interest. The additional amount is approximately $2 million USD. On February 12, 2021, Guatemala filed an application for annulment of the Second Award with ICSID. On March 31, 2021, ICSID constituted an ad hoc Committee to oversee the annulment proceeding. A three-day hearing was held before the ad hoc Committee beginning on July 27, 2022. A decision on the annulment of the Second Award is expected in Q4 2023. To date, the total of the Second Award, with interest, is approximately $64 million USD. Results to date do not reflect any benefit of the Second Award.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at September 30, 2022, TEC has estimated its financial liability to be $19 million ($14 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 TEC. The estimates to perform the work are based on TEC's 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, TEC could be liable for more than TEC's 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 2021 annual audited consolidated financial statements. Risks associated with derivative instruments and fair value measurements are discussed in note 12 and note 13. There have been no material changes to the principal financial risks as of September 30, 2022, except for the following:

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. Regulatory and political risk can include change in regulatory frameworks, shifts in government policy, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, M&NP and Lucelec. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the Canadian Energy Regulator ("CER") on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement expiring in 2034, with Repsol Energy Canada ("REC"). The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract.

Changes in government and shifts in government policy can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. State and local policies in some US jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas while in other jurisdictions policies have been adopted to prevent limitations on the use of natural gas. Changes in applicable state or local laws and regulations could adversely impact PGS and NMGC.

Emera's rate-regulated subsidiaries are subject to regulatory processes. During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

On November 9, 2022, the Nova Scotia provincial government enacted Bill 212, "Public Utilities Act (amended)". This government intervention in the regulatory process has resulted in an increase in political risk and a reduction in the stability and predictability of NSPI's regulatory environment. This legislation sets an unfavourable precedent and significantly increases the risk associated with NSPI's current and future ability to recover prudently incurred costs including capital investments and regulatory assets.

D. Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2021 audited annual consolidated financial statements, with material updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $125 million USD (December 31, 2021 - $148 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually, as required.

Emera Inc. has issued a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

TECO Energy issued a guarantee in connection with SeaCoast's performance obligations under a firm service agreement, which expires on December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of $13 million USD if SeaCoast fails to pay or perform under the firm service agreement. In the event that TECO Energy's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would need to provide either a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $13 million USD.

21. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the	Nine months ended September 30	
millions of dollars	**2022**	2021
Changes in non-cash working capital:		
Inventory	**$ (162)**	$ (76)
Receivables and other current assets	**(259)**	(223)
Accounts payable	**471**	282
Other current liabilities	**99**	88
Total non-cash working capital	**$ 149**	$ 71
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 172**	$ 157
Reclassification of long-term debt to short-term debt	**$ 500**	-
Decrease in accrued capital expenditures	**$ (8)**	$ (1)

22. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any Variable Interest Entities ("VIE") or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method.

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

BLPC has established a Self-Insurance Fund ("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, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Condensed Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

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

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

As at	**September 30, 2022**		December 31, 2021	
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)	**$ 514**	**$ 6**	$ 533	$ 11

23. COMPARATIVE INFORMATION

These unaudited condensed consolidated interim financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

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, 2022, the date the unaudited condensed consolidated interim financial statements were issued.