EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2021 and 2020

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Operating revenues				
Regulated electric	**$ 1,244**	$ 1,101	**$ 3,445**	$ 3,352
Regulated gas	**237**	192	**874**	730
Non-regulated	**(333)**	(130)	**(422)**	(113)
Total operating revenues (note 6)	**1,148**	1,163	**3,897**	3,969
Operating expenses				
Regulated fuel for generation and purchased power	**476**	319	**1,263**	1,041
Regulated cost of natural gas	**71**	40	**297**	189
Non-regulated fuel for generation and purchased power	**-**	(1)	**(1)**	3
Operating, maintenance and general ("OM&G")	**341**	334	**1,003**	1,046
Provincial, state and municipal taxes	**85**	81	**246**	243
Depreciation and amortization	**228**	217	**675**	664
Impairment charge	**-**	-	**-**	25
Total operating expenses	**1,201**	990	**3,483**	3,211
Income (loss) from operations	**(53)**	173	**414**	758
Income from equity investments (note 8)	**33**	32	**111**	113
Other income, net (note 9)	**22**	21	**67**	633
Interest expense, net	**150**	163	**460**	520
Income (loss) before provision for income taxes	**(148)**	63	**132**	984
Income tax expense (recovery) (note 10)	**(92)**	(21)	**(91)**	284
Net income (loss)	**(56)**	84	**223**	700
Non-controlling interest in subsidiaries	**-**	-	**1**	1
Preferred stock dividends	**14**	-	**36**	34
Net income (loss) attributable to common shareholders	**$ (70)**	$ 84	**$ 186**	$ 665
Weighted average shares of common stock outstanding (in millions) (note 12)				
Basic	**258.5**	248.4	**256.0**	246.6
Diluted	**258.5**	248.7	**256.4**	247.0
Earnings (loss) per common share (note 12)				
Basic	**$ (0.27)**	$ 0.34	**$ 0.73**	$ 2.70
Diluted	**$ (0.27)**	$ 0.34	**$ 0.73**	$ 2.69
Dividends per common share declared	**$ 0.6375**	$ -	**$ 1.9125**	$ 1.8375

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

Emera Incorporated
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of Canadian dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Net income (loss)	**$ (56)**	$ 84	**$ 223**	$ 700
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	**243**	(189)	**(1)**	207
Unrealized gains (losses) on net investment hedges (2) (3)	**(35)**	34	**(1)**	(41)
Cash flow hedges				
Net derivative gains (losses) (4)	**-**	1	**18**	(1)
Less: reclassification adjustment for losses (gains) included in income	**(1)**	-	**(1)**	2
Net effects of cash flow hedges	**(1)**	1	**17**	1
Net change in unrecognized pension and post-retirement benefit obligation	**4**	4	**13**	2
Other comprehensive income (loss) (5)	**211**	(150)	**28**	169
Comprehensive income (loss)	**155**	(66)	**251**	869
Comprehensive income attributable to non-controlling interest	**-**	-	**1**	2
Comprehensive income (loss) of Emera Incorporated	**$ 155**	$ (66)	**$ 250**	$ 867

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

(1) Net of tax expense of nil (2020 - $4 million recovery) for the three months ended September 30, 2021 and tax expense of $5 million (2020 – $2 million expense) for the nine months ended September 30, 2021.
(2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.
(3) Net of tax recovery of $6 million (2020 - nil) for the three months ended September 30, 2021 and tax expense of nil (2020 – $1 million recovery) for the nine months ended September 30, 2021.
(4) Net of tax expense of nil (2020 - nil) for the three months ended September 30, 2021 and tax expense of $6 million (2020 – nil) for the nine months ended September 30, 2021.
(5) Net of tax recovery of $6 million (2020 - $4 million recovery) for the three months ended September 30, 2021 and tax expense of $11 million (2020 – $1 million tax expense) for the nine months ended September 30, 2021.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars		**September 30 2021**		December 31 2020
Assets				
Current assets				
Cash and cash equivalents	**$**	**440**	$	220
Restricted cash (note 24)		**36**		34
Inventory		**531**		453
Derivative instruments (notes 14 and 15)		**249**		73
Regulatory assets (note 7)		**181**		165
Receivables and other current assets (note 17)		**1,372**		1,233
		2,809		2,178
Property, plant and equipment, net of accumulated depreciation and amortization of $9,214 and $8,714, respectively		**20,491**		19,535
Other assets				
Deferred income taxes (note 10)		**364**		209
Derivative instruments (notes 14 and 15)		**90**		25
Regulatory assets (note 7)		**1,595**		1,419
Net investment in direct financing lease		**465**		475
Investments subject to significant influence (note 8)		**1,379**		1,346
Goodwill		**5,724**		5,720
Other long-term assets		**325**		327
		9,942		9,521
Total assets	**$**	**33,242**	$	31,234

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited) – Continued

As at millions of Canadian dollars	**September 30 2021**	December 31 2020
Liabilities and Equity		
Current liabilities		
Short-term debt (note 19)	**$ 1,350**	$ 1,625
Current portion of long-term debt (note 20)	**567**	1,382
Accounts payable	**1,438**	1,148
Derivative instruments (notes 14 and 15)	**558**	251
Regulatory liabilities (note 7)	**284**	129
Other current liabilities	**433**	340
	4,630	4,875
Long-term liabilities		
Long-term debt (note 20)	**13,869**	12,339
Deferred income taxes (note 10)	**1,780**	1,629
Derivative instruments (notes 14 and 15)	**156**	87
Regulatory liabilities (note 7)	**1,828**	1,832
Pension and post-retirement liabilities (note 18)	**397**	453
Other long-term liabilities	**798**	781
	18,828	17,121
Equity		
Common stock (note 11)	**7,103**	6,705
Cumulative preferred stock (note 22)	**1,422**	1,004
Contributed surplus	**79**	79
Accumulated other comprehensive loss (note 13)	**(51)**	(79)
Retained earnings	**1,197**	1,495
Total Emera Incorporated equity	**9,750**	9,204
Non-controlling interest in subsidiaries	**34**	34
Total equity	**9,784**	9,238
Total liabilities and equity	**$ 33,242**	$ 31,234

Commitments and contingencies (note 21)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard" *"Scott Balfour"*

Chair of the Board **President and Chief Executive Officer**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Nine months ended September 30 **2021**	 2020
Operating activities		
Net income	**$ 223**	$ 700
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**682**	678
Income from equity investments, net of dividends	**(56)**	(58)
Allowance for equity funds used during construction	**(44)**	(32)
Deferred income taxes, net	**(111)**	322
Net change in pension and post-retirement liabilities	**(25)**	(20)
Regulated fuel adjustment mechanism	**(71)**	(33)
Net change in fair value of derivative instruments	**416**	66
Net change in regulatory assets and liabilities	**(124)**	(53)
Net change in capitalized transportation capacity	**96**	69
Impairment charges	**-**	25
Gain on sale, excluding transaction costs	**-**	(603)
Other operating activities, net	**49**	40
Changes in non-cash working capital (note 23)	**71**	139
Net cash provided by operating activities	**1,106**	1,240
Investing activities		
Proceeds from dispositions	**3**	1,401
Additions to property, plant and equipment	**(1,596)**	(1,935)
Other investing activities	**17**	(2)
Net cash used in investing activities	**(1,576)**	(536)
Financing activities		
Change in short-term debt, net	**88**	252
Proceeds from short-term debt with maturities greater than 90 days	**-**	399
Repayment of short-term debt with maturities greater than 90 days	**(377)**	(688)
Proceeds from long-term debt, net of issuance costs	**2,329**	422
Retirement of long-term debt	**(1,541)**	(485)
Net repayments under committed credit facilities	**(87)**	(326)
Issuance of common stock, net of issuance costs	**236**	181
Issuance of preferred stock, net of issuance costs	**416**	-
Dividends on common stock	**(329)**	(309)
Dividends on preferred stock	**(36)**	(33)
Other financing activities	**(6)**	(8)
Net cash provided by (used in) financing activities	**693**	(595)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(1)**	(48)
Net increase in cash, cash equivalents, and restricted cash	**222**	61
Cash, cash equivalents and restricted cash, beginning of period	**254**	274
Cash, cash equivalents and restricted cash, end of period	**$ 476**	$ 335
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 198**	$ 265
Short-term investments	**242**	21
Restricted cash	**36**	49
Cash, cash equivalents and restricted cash	**$ 476**	$ 335

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

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

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("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 income (loss) of Emera Incorporated	**-**	**-**	**-**	**-**	**(56)**	**-**	**(56)**
Other comprehensive gain, net of tax recovery of $6 million	**-**	**-**	**-**	**211**	**-**	**-**	**211**
Dividends declared on preferred stock (1)	**-**	**-**	**-**	**-**	**(14)**	**-**	**(14)**
Dividends declared on common stock ($0.6375/share)	**-**	**-**	**-**	**-**	**(164)**	**-**	**(164)**
Issuance of preferred shares, net of after-tax issuance costs (note 22)	**-**	**222**	**-**	**-**	**-**	**-**	**222**
Common stock issued under purchase plan	**55**	**-**	**-**	**-**	**-**	**-**	**55**
Issuance of common stock, net of after-tax issuance costs	**83**	**-**	**-**	**-**	**-**	**-**	**83**
Senior management stock options exercised	**8**	**-**	**-**	**-**	**-**	**-**	**8**
Balance, September 30, 2021	**$ 7,103**	**$ 1,422**	**$ 79**	**$ (51)**	**$ 1,197**	**$ 34**	**$ 9,784**

millions of Canadian dollars							
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 ($1.9125/share)	**-**	**-**	**-**	**-**	**(486)**	**-**	**(486)**
Issuance of preferred shares, net of after-tax issuance costs (note 22)	**-**	**418**	**-**	**-**	**-**	**-**	**418**
Common stock issued under purchase plan	**174**	**-**	**-**	**-**	**-**	**-**	**174**
Issuance of common stock, net of after-tax issuance costs	**211**	**-**	**-**	**-**	**-**	**-**	**211**
Senior management stock options exercised	**10**	**-**	**-**	**-**	**-**	**-**	**10**
Other	**3**	**-**	**-**	**-**	**2**	**(1)**	**4**
Balance, September 30, 2021	**$ 7,103**	**$ 1,422**	**$ 79**	**$ (51)**	**$ 1,197**	**$ 34**	**$ 9,784**

The accompanying notes are an integral part of these condensed consolidated 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
Condensed Consolidated Statements of Changes in Equity (Unaudited)

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("AOCI")	Retained Earnings	Non-Controlling Interest	Total Equity
For the three months ended September 30, 2020							
Balance, June 30, 2020	$ 6,435	$ 1,004	$ 78	$ 413	$ 1,298	$ 36	$ 9,264
Net income of Emera Incorporated	-	-	-	-	84	-	84
Other comprehensive loss, net of tax recovery of $4 million	-	-	-	(150)	-	-	(150)
Common stock issued under purchase plan	53	-	-	-	-	-	53
Issuance of common stock, net of after-tax issuance costs	52					-	52
Other	1	-	-	-	-	(1)	-
Balance, September 30, 2020	$ 6,541	$ 1,004	$ 78	$ 263	$ 1,382	$ 35	$ 9,303
For the nine months ended September 30, 2020							
Balance, December 31, 2019	$ 6,216	$ 1,004	$ 78	$ 95	$ 1,173	$ 35	$ 8,601
Net income of Emera Incorporated	-	-	-	-	699	1	700
Other comprehensive income, net of tax expense of $1 million	-	-	-	168	-	1	169
Dividends declared on preferred stock (2)	-	-	-	-	(34)	-	(34)
Dividends declared on common stock ($1.8375/share)	-	-	-	-	(449)	-	(449)
Common stock issued under purchase plan	152	-	-	-	-	-	152
Issuance of common stock, net of after-tax issuance costs	151	-	-	-	-	-	151
Senior management stock option exercised	20	-	(1)	-	-	-	19
Adoption of credit losses accounting standard	-	-	-	-	(7)	-	(7)
Other	2	-	1	-	-	(2)	1
Balance, September 30, 2020	$ 6,541	$ 1,004	$ 78	$ 263	$ 1,382	$ 35	$ 9,303

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

(1) Series A; $0.4791/share, Series B; $0.5691/share, Series C; $0.88518/share, Series E; $0.84375/share, Series F; $0.79089/share and Series H; $0.91875

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 2021 and 2020

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, 2021, 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 $1.6 billion transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project went in service on January 15, 2018; and
        - a 39.2 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 to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and Nalcor recognized the first flow of energy from Labrador to Newfoundland in June 2018. Three of four generators at Muskrat Falls are completed and available for service, the first in Q3 2020, the second in Q2 2021 and the third in Q3 2021. Nalcor continues to advance towards construction completion with final commissioning of Muskrat Falls and LIL targeted for Q1 2022. For further details, refer to note 21.

- 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;
    - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), a vertically integrated regulated electric utility on the island of Dominica; and
    - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

  On March 24, 2020, Emera completed the sale of Emera Maine which was previously included in the Other Electric Utilities segment. For further information, refer to note 4.

- 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;
    - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida;
    - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas ("LNG") 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; 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.

- 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 renewables 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.

In 2020, the outbreak of COVID-19 resulted in governments worldwide enacting emergency measures to combat the spread of the virus. While management considered the impact of COVID-19 in the Company's estimates and results, the financial statements for three and nine months ended September 30, 2021 and 2020 were not materially impacted by COVID-19.

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, 2020, except as described in note 2.

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, 2021.

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

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, 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.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments were required for the three and nine months ended September 30, 2021.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. Actual results may differ significantly from these estimates.

Goodwill Impairment Assessments

Management considered whether the potential impacts of the COVID-19 pandemic on future earnings required testing for goodwill impairment in Q3 2021 and determined that it is more likely than not that the fair value of reporting units that include goodwill exceeded their respective carrying amounts as of September 30, 2021.

As of September 30, 2021, $5.7 billion of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Given the significant excess of fair value over carrying amounts calculated for these reporting units as of the last quantitative test performed in Q4 2019, and the results of the qualitative assessment performed in Q4 2020, management does not expect the COVID-19 pandemic to have an impact on the goodwill associated with these reporting units.

As of September 30, 2021, $68 million of Emera's goodwill was related to GBPC. In Q4 2020, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in forecasted future earnings due to limited excess of fair value over the carrying value. As part of the assessment management considered potential impacts of the COVID-19 pandemic on the future earnings of the reporting unit. No adverse changes in significant assumptions were identified in Q3 2021 and no impairment has been recorded for the three and nine months ended September 30, 2021 associated with this goodwill. Adverse changes in significant assumptions could result in a future impairment.

Long-Lived Assets Impairment Assessments

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at September 30, 2021, there are no indications of impairment of Emera's long-lived assets. There is currently no indication that future cash flows would be impacted to a point where the Company's long-lived assets would not be recoverable.

No impairment charges were recognized for the three and nine months ended September 30, 2021. Impairment charges of nil and $25 million ($26 million after tax) were recognized on certain assets for the three and nine months ended September 30, 2020, respectively.

Receivables and Allowance for Credit Losses

Management estimates credit losses related to accounts receivable after considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. The economic impact of COVID-19, in the service territories where Emera operates, has impacted the aging of customer receivables resulting in higher allowances for credit losses related to customer receivables, however it has not had a material impact on earnings.

Pension and Other Post-Retirement Employee Benefits

The COVID-19 pandemic could impact key actuarial assumptions used to account for employee post-retirement benefits as a result of changes in the market. These changes could impact assumptions including the anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation, benefit costs and annual pension funding requirements. Fluctuations in actual equity market returns and changes in interest rates as a result of the COVID-19 pandemic may also result in changes to pension costs and funding in future periods.

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. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2021, are described as follows:

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity

The Company adopted Accounting Standard Update ("ASU") 2020-06, Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40) effective January 1, 2021 using the modified retrospective approach. The standard simplifies the accounting for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs that have been issued, but are not yet effective, are consistent with those disclosed in the Company's 2020 audited consolidated financial statements, with updates noted below.

Guaranteed Debt Securities Disclosure Requirements

In October 2020, the FASB issued ASU 2020-09, *Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762*. The change in the standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying and focusing the disclosure models, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. The guidance will be effective for annual reports filed for fiscal years ending after January 4, 2021, with early adoption permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

4. DISPOSITIONS

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of approximately $2.0 billion including cash proceeds of $1.4 billion, transferred debt and working capital adjustments. A gain on disposition of $585 million ($309 million after tax) net of transaction costs, was recognized in the Other segment and included in "Other income" on the Condensed Consolidated Statements of Income.

5. 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. Emera's five reportable segments are Florida Electric Utility, Canadian Electric Utilities, Other Electric Utilities, Gas Utilities and Infrastructure, and Other.

millions of Canadian 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, 2021							
Operating revenues from external customers (1)	$ 796	$ 328	$ 120	$ 241	$ (337)	$ -	$ 1,148
Inter-segment revenues (1)	2	-	-	1	7	(10)	-
Total operating revenues	798	328	120	242	(330)	(10)	1,148
Regulated fuel for generation and purchased power	274	144	59	-	-	(1)	476
Regulated cost of natural gas	-	-	-	71	-	-	71
Depreciation and amortization	120	61	14	31	2	-	228
Interest expense, net	34	32	6	12	66	-	150
Internally allocated interest (2)	-	-	-	3	(3)	-	-
OM&G	133	72	37	79	24	(4)	341
Income tax expense (recovery)	26	(5)	-	9	(122)	-	(92)
Net income (loss) attributable to common shareholders	169	42	8	29	(318)	-	(70)
For the nine months ended September 30, 2021							
Operating revenues from external customers (1)	2,012	1,112	321	886	(434)	-	3,897
Inter-segment revenues (1)	5	-	-	3	21	(29)	-
Total operating revenues	2,017	1,112	321	889	(413)	(29)	3,897
Regulated fuel for generation and purchased power	628	484	154	-	-	(3)	1,263
Regulated cost of natural gas	-	-	-	297	-	-	297
Depreciation and amortization	351	184	44	90	6	-	675
Interest expense, net	105	100	16	38	201	-	460
Internally allocated interest (2)	-	-	-	10	(10)	-	-
OM&G	381	222	98	238	74	(10)	1,003
Income tax expense (recovery)	59	3	1	43	(197)	-	(91)
Net income (loss) attributable to common shareholders	377	174	14	143	(522)	-	186
As at September 30, 2021							
Total assets	17,637	7,101	1,417	6,508	1,696	(1,117) (3)	33,242

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to 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.

(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

millions of Canadian 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, 2020							
Operating revenues from external customers (1)	$ 672	$ 324	$ 105	$ 196	$ (134)	$ -	$ 1,163
Inter-segment revenues (1)	2	-	-	1	1	(4)	-
Total operating revenues	674	324	105	197	(133)	(4)	1,163
Regulated fuel for generation and purchased power	135	143	44	-	-	(3)	319
Regulated cost of natural gas	-	-	-	40	-	-	40
Depreciation and amortization	115	59	13	28	2	-	217
Interest expense, net	37	35	6	13	72	-	163
Internally allocated interest (2)	-	-	-	3	(3)	-	-
OM&G	137	66	37	79	17	(2)	334
Income tax expense (recovery)	33	1	-	6	(61)	-	(21)
Net income (loss) attributable to common shareholders	175	35	6	20	(152)	-	84
For the nine months ended September 30, 2020							
Operating revenues from external customers (1)	1,864	1,117	371	742	(125)	-	3,969
Inter-segment revenues (1)	5	-	-	6	11	(22)	-
Total operating revenues	1,869	1,117	371	748	(114)	(22)	3,969
Regulated fuel for generation and purchased power	407	493	148	-	-	(7)	1,041
Regulated cost of natural gas	-	-	-	189	-	-	189
Depreciation and amortization	343	175	57	83	6	-	664
Interest expense, net	116	105	26	43	230	-	520
Internally allocated interest (2)	-	-	-	10	(10)	-	-
OM&G	407	214	120	242	74	(11)	1,046
Gain on sale, net of transaction costs	-	-	-	-	585	-	585
Impairment charges	-	-	-	-	25	-	25
Income tax expense (recovery)	75	13	(8)	36	168	-	284
Net income (loss) attributable to common shareholders	400	164	25	117	(41)	-	665
As at December 31, 2020							
Total assets	16,889	6,752	1,365	6,067	1,234	(1,073) (3)	31,234

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to 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.
(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

6. REVENUE

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

millions of Canadian 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, 2021							
Regulated							
Electric Revenue							
Residential	$ 454	$ 154	$ 44	$ -	$ -	$ -	$ 652
Commercial	214	97	64	-	-	-	375
Industrial	58	61	8	-	-	-	127
Other electric and regulatory deferrals	70	7	2	-	-	-	79
Other (1)	2	9	2	-	-	(2)	11
Regulated electric revenue	798	328	120	-	-	(2)	1,244
Gas Revenue							
Residential	-	-	-	102	-	-	102
Commercial	-	-	-	76	-	-	76
Industrial	-	-	-	16	-	-	16
Finance income (2)(3)	-	-	-	15	-	-	15
Other	-	-	-	29	-	(1)	28
Regulated gas revenue	-	-	-	238	-	(1)	237
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	(4)	-	(4)
Energy sales	-	-	-	-	5	(4)	1
Other	-	-	-	4	3	-	7
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							
Electric Revenue							
Residential	$ 1,086	$ 588	$ 121	$ -	$ -	$ -	$ 1,795
Commercial	550	303	166	-	-	-	1,019
Industrial	156	176	21	-	-	-	353
Other electric and regulatory deferrals	214	21	5	-	-	-	240
Other (1)	11	24	8	-	-	(5)	38
Regulated electric revenue	2,017	1,112	321	-	-	(5)	3,445
Gas Revenue							
Residential	-	-	-	430	-	-	430
Commercial	-	-	-	268	-	-	268
Industrial	-	-	-	48	-	(1)	47
Finance income (2)(3)	-	-	-	43	-	-	43
Other	-	-	-	88	-	(2)	86
Regulated gas revenue	-	-	-	877	-	(3)	874
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	63	-	63
Energy sales	-	-	-	-	17	(15)	2
Other	-	-	-	12	8	-	20
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.

millions of Canadian 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, 2020							
Regulated							
Electric Revenue							
Residential	$ 404	$ 161	$ 41	$ -	$ -	$ -	$ 606
Commercial	170	93	54	-	-	-	317
Industrial	41	57	6	-	-	-	104
Other electric and regulatory deferrals	54	7	3	-	-	-	64
Other (1)	5	6	1	-	-	(2)	10
Regulated electric revenue	674	324	105	-	-	(2)	1,101
Gas Revenue							
Residential	-	-	-	77	-	-	77
Commercial	-	-	-	52	-	-	52
Industrial	-	-	-	13	-	-	13
Finance income (2)(3)	-	-	-	15	-	-	15
Other	-	-	-	36	-	(1)	35
Regulated gas revenue	-	-	-	193	-	(1)	192
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	(12)	-	(12)
Energy sales	-	-	-	-	6	(4)	2
Other	-	-	-	4	4	-	8
Mark-to-market (3)	-	-	-	-	(131)	3	(128)
Non-regulated revenue	-	-	-	4	(133)	(1)	(130)
Total operating revenues	$ 674	$ 324	$ 105	$ 197	$ (133)	$ (4)	$ 1,163
For the nine months ended September 30, 2020							
Regulated							
Electric Revenue							
Residential	$ 1,031	$ 607	$ 138	$ -	$ -	$ -	$ 1,776
Commercial	506	303	180	-	-	-	989
Industrial	135	164	25	-	-	-	324
Other electric and regulatory deferrals	183	24	8	-	-	-	215
Other (1)	14	19	20	-	-	(5)	48
Regulated electric revenue	1,869	1,117	371	-	-	(5)	3,352
Gas Revenue							
Residential	-	-	-	338	-	-	338
Commercial	-	-	-	193	-	-	193
Industrial	-	-	-	40	-	(1)	39
Finance income (2)(3)	-	-	-	45	-	-	45
Other	-	-	-	120	-	(5)	115
Regulated gas revenue	-	-	-	736	-	(6)	730
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	16	-	16
Energy sales	-	-	-	-	12	(12)	-
Other	-	-	-	12	13	-	25
Mark-to-market (3)	-	-	-	-	(155)	1	(154)
Non-regulated revenue	-	-	-	12	(114)	(11)	(113)
Total operating revenues	$ 1,869	$ 1,117	$ 371	$ 748	$ (114)	$ (22)	$ 3,969

(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, 2021, the aggregate amount of the transaction price allocated to remaining performance obligations was $435 million (2020 – $334 million). This amount includes $144 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 2040.

7. 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 2020 annual audited consolidated financial statements.

As at millions of Canadian dollars	**September 2021**	December 31 2020
Regulatory assets		
Deferred income tax regulatory assets	**$ 966**	$ 887
Pension and post-retirement medical plan	**370**	394
NMGC winter event gas cost recovery	**129**	-
Cost recovery clauses	**64**	49
Regulated fuel adjustment mechanism	**50**	-
Storm restoration regulatory asset	**42**	41
Environmental remediations	**30**	28
Stranded cost recovery	**26**	26
Deferrals related to derivative instruments	**24**	65
Demand side management deferral	**11**	15
Unamortized defeasance costs	**11**	13
Other	**53**	66
	$ 1,776	$ 1,584
Current	**$ 181**	$ 165
Long-term	**1,595**	1,419
Total regulatory assets	**$ 1,776**	$ 1,584
Regulatory liabilities		
Deferred income tax regulatory liabilities	**$ 902**	$ 933
Accumulated reserve - cost of removal	**825**	865
Deferrals related to derivative instruments	**260**	15
Storm reserve	**58**	62
Cost recovery clauses	**28**	31
Self-insurance fund (note 24)	**28**	28
Regulated fuel adjustment mechanism	**-**	21
Other	**11**	6
	$ 2,112	$ 1,961
Current	**$ 284**	$ 129
Long-term	**1,828**	1,832
Total regulatory liabilities	**$ 2,112**	$ 1,961

Tampa Electric

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a settlement agreement (the “Settlement Agreement”) by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including, Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. It also provides for a 25 basis point increase in the allowed ROE range and mid-point, and $10 million USD of additional revenue, if U.S. Treasury Bond yields exceed a specific threshold set on the date the FPSC votes to approve the agreement. Under the agreement, base rates will not further change from January 1, 2022 through December 31, 2024, unless Tampa Electric’s earned ROE were to fall below the bottom of the range during that time. The Settlement Agreement contains a provision whereby Tampa Electric agrees to quantify the future impact of a change in tax rates on net operating income through a reduction or increase in base revenues within 180 days of when such tax change becomes law or its effective date. On October 21, 2021, the FPSC approved the settlement agreement and the final order, reflecting such approval, is expected to be issued in November 2021.

On October 12, 2021, the FPSC approved the true-up filing for SoBRA tranche 3, included in base rates as of January 2020. An estimated $4 million true-up is being returned to customers during 2021. The true-up for SoBRA tranche 4 will be filed in 2022.

On July 19, 2021, Tampa Electric requested a mid-course adjustment of $83 million USD to its fuel and capacity charges, effective with September 2021 customer bills, due to an increase in fuel commodity and capacity costs in 2021. On August 3, 2021, the FPSC approved the request to recover the costs during the months of September through December 2021.

NMGC

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause. On April 16, 2021, NMGC filed a Motion for Extraordinary Relief, as permitted by the NMPRC rules, to extend the terms of the repayment of the incremental gas costs and to recover a carrying charge. On June 15, 2021, the NMPRC approved the recovery of $108 million USD and related borrowing costs over a period of 30 months beginning July 1, 2021.

BLPC

BLPC currently operates pursuant to a franchise to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists, to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. In March 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The new licenses are expected to take effect in 2021 on completion of the legislative process and will have terms ranging from 5 to 30 years. BLPC anticipates that any increased costs associated with the implementation of the new multi-licensed structure will be recoverable through BLPC’s regulatory framework. BLPC is currently assessing the full impact of the new licenses on its business and working towards the successful implementation of the licenses.

On October 4, 2021 BLPC submitted a general rate review application to the 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 to be effective April 2022. The application includes a request for allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. A decision is expected from the FTC by Q2 2022.

On October 21, 2021 the FTC approved BLPC's application to implement a fuel hedging program which will be incorporated into the calculation of the fuel clause adjustment.

GBPC

On September 23, 2021, GBPC filed an application for rate review with the GBPA. The application seeks a revision in base rates, charges and tariff classifications effective January 1, 2022 for a three-year period ending December 31, 2024. GBPC's proposed rates would reinstate the amortization of regulatory assets which had been deferred as part of the five-year rate stabilization plan. Rates were designed based on an 8.5 per cent to 9.0 per cent allowable regulated return on rate base and a target regulatory ROE of 12.84 per cent. A decision is expected from the GBPA by the end of 2021.

8. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

	Carrying Value as at		Equity Income for the three months ended		Equity Income for the nine months ended		Percentage of Ownership
	September 30	December 31	September 30		September 30		
millions of Canadian dollars	**2021**	2020	**2021**	2020	**2021**	2020	**2021**
LIL (1)	**$ 668**	$ 629	**$ 13**	$ 13	**$ 39**	$ 37	39.2
NSPML	**542**	547	**12**	11	**39**	38	100.0
M&NP (2)	**126**	129	**5**	5	**15**	14	12.9
Lucelec (2)	**43**	41	**1**	1	**3**	3	19.5
Bear Swamp (3)	**-**	-	**2**	2	**15**	21	50.0
	$ 1,379	$ 1,346	**$ 33**	$ 32	**$ 111**	$ 113	

(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 $106 million (2020 – $118 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 24). NSPML's consolidated summarized balance sheet is as follows:

As at millions of Canadian dollars	**September 30 2021**	December 31 2020
Current assets	**$ 36**	$ 57
Property, plant and equipment	**1,600**	1,629
Regulatory assets	**258**	210
Non-current assets	**30**	32
Total assets	**$ 1,924**	$ 1,928
Current liabilities	**$ 60**	$ 56
Long-term debt	**1,209**	1,228
Non-current liabilities	**113**	97
Equity	**542**	547
Total liabilities and equity	**$ 1,924**	$ 1,928

9. OTHER INCOME, NET

For the millions of Canadian dollars	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Allowance for equity funds used during construction	**$ 17**	$ 12	**$ 44**	$ 32
Gain on sale, net of transaction costs (1)	**-**	-	**-**	585
Other	**5**	9	**23**	16
	$ 22	$ 21	**$ 67**	$ 633

(1) For further details related to the gain on sale of Emera Maine, refer to note 4

10. 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 Canadian dollars	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Income (loss) before provision for income taxes	**$ (148)**	$ 63	**$ 132**	$ 984
Statutory income tax rate	**29.0%**	29.5%	**29.0%**	29.5%
Income taxes, at statutory income tax rate	**(43)**	18	**38**	290
Additional impact from the sale of Emera Maine	**-**	-	**-**	102
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(16)**	(8)	**(47)**	(35)
Amortization of deferred income tax regulatory liabilities	**(12)**	(14)	**(28)**	(41)
Foreign tax rate variance	**(11)**	(10)	**(27)**	(27)
Tax effect of equity earnings	**(3)**	(4)	**(12)**	(12)
Tax credits	**(3)**	(3)	**(10)**	(9)
Manufacturing allowance	**(2)**	(1)	**(5)**	(4)
Revaluation of deferred income taxes due to change in Nova Scotia tax rate	**-**	-	**-**	12
Other	**(2)**	1	**-**	8
Income tax expense (recovery)	**$ (92)**	$ (21)	**$ (91)**	$ 284
Effective income tax rate	**62%**	(33)%	**(69)%**	29%

The change in the effective income tax rate for the third quarter and year-to-date in 2021 compared to the same periods in 2020 was primarily due to decreased income before provision for income taxes and higher deferred income taxes on regulated income recorded as regulatory assets and liabilities. Year-to-date, the change was also due to the additional impact from the sale of Emera Maine in 2020.

11. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars	
Balance, December 31, 2020	251.43	$	6,705
Issuance of common stock (1)	3.74		211
Issued for cash under Purchase Plans at market rate	3.25		177
Discount on shares purchased under Dividend Reinvestment Plan	-		(3)
Options exercised under senior management share option plan	0.22		10
Employee Share Purchase Plan	-		3
Balance, September 30, 2021	**258.64**	**$**	**7,103**

(1) In Q3 2021, 1,402,797 common shares were issued under Emera's ATM program at an average price of 59.03 per share for gross proceeds of $83 million ($82 million net of after-tax issuance costs). For the nine months ended September 30, 2021, 3,739,823 common shares were issued under Emera's ATM program at an average price of $56.88 per share for gross proceeds of $213 million ($211 million net of after-tax issuance costs). As at September 30, 2021, an aggregate gross sales limit of $531 million remained available for issuance under the ATM program.

ATM Equity Program

On August 12, 2021, Emera renewed its ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was renewed pursuant to a prospectus supplement to the Company's short form base shelf prospectus dated August 5, 2021. The ATM program is expected to remain in effect until September 5, 2023.

12. EARNINGS PER SHARE

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

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Numerator				
Net income (loss) attributable to common shareholders	**$ (70.0)**	$ 84.3	**$ 186.4**	$ 665.4
Diluted numerator	**(70.0)**	84.3	**186.4**	665.4
Denominator				
Weighted average shares of common stock outstanding	**257.3**	247.1	**254.7**	245.3
Weighted average deferred share units outstanding	**1.2**	1.3	**1.3**	1.3
Weighted average shares of common stock outstanding – basic	**258.5**	248.4	**256.0**	246.6
Stock-based compensation (1)	**-**	0.3	**0.4**	0.4
Weighted average shares of common stock outstanding – diluted	**258.5**	248.7	**256.4**	247.0
Earnings (loss) per common share				
Basic	**$ (0.27)**	$ 0.34	**$ 0.73**	$ 2.70
Diluted	**$ (0.27)**	$ 0.34	**$ 0.73**	$ 2.69

(1) 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 a net loss for the quarter.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss), net of tax, are as follows:

millions of Canadian 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, 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)**
For the nine months ended September 30, 2020						
Balance, January 1, 2020	$ 253	$ 4	$ (1)	$ (1)	$ (160)	$ 95
Other comprehensive income (loss) before reclassifications	206	(41)	(1)	-	-	164
Amounts reclassified from AOCI	-	-	2	-	2	4
Net current period other comprehensive income (loss)	206	(41)	1	-	2	168
Balance, September 30, 2020	$ 459	$ (37)	$ -	$ (1)	$ (158)	$ 263

The reclassifications out of accumulated other comprehensive income (loss) are as follows:

For the millions of Canadian dollars		Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
	Affected line item in the Consolidated Financial Statements	Amounts reclassified from AOCI			
Losses (gain) on derivatives recognized as cash flow hedges					
Foreign exchange forwards	Interest expense	**$ (1)**	$ -	**$ (1)**	$ 2
Total		**$ (1)**	$ -	**$ (1)**	$ 2
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses	Other income, net	**$ 4**	$ 5	**$ 13**	$ 11
Past service costs (gains)	Other income, net	**-**	(1)	**-**	(1)
Amounts reclassified into obligations	Pension and post-retirement liabilities	**-**	-	**-**	(8)
Total		**4**	4	**13**	2
Total reclassifications out of AOCI, for the period		**$ 3**	$ 4	**$ 12**	$ 4

14. 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 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 Florida Public Service Commission 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 Canadian dollars	**September 30 2021**	December 31 2020	**September 30 2021**	December 31 2020
Cash flow hedges				
Interest rate hedge	**$ -**	$ 1	**$ -**	$ -
	-	1	**-**	-
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**89**	1	**20**	6
Power purchases	**112**	10	**15**	34
Natural gas purchases and sales	**57**	4	**5**	2
Heavy fuel oil purchases	**21**	1	**-**	5
Foreign exchange forwards	**6**	-	**9**	17
	285	16	**49**	64
HFT derivatives				
Power swaps and physical contracts	**54**	13	**52**	13
Natural gas swaps, futures, forwards, physical contracts	**237**	139	**863**	346
	291	152	**915**	359
Other derivatives				
Equity derivatives	**9**	-	**-**	1
Foreign exchange forwards	**4**	15	**-**	-
	13	15	**-**	1
Total gross current derivatives	**589**	184	**964**	424
Impact of master netting agreements with intent to settle net or simultaneously	**(250)**	(86)	**(250)**	(86)
Total derivatives	**$ 339**	$ 98	**$ 714**	$ 338
Current	**$ 249**	$ 73	**$ 558**	$ 251
Long-term	**90**	25	**156**	87
Total derivatives	**$ 339**	$ 98	**$ 714**	$ 338

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

Details of master netting agreements, shown net on the Condensed Consolidated Balance Sheets, are summarized in the following table:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**September 30 2021**	December 31 2020	**September 30 2021**	December 31 2020
Regulatory deferral	**$ 24**	$ 2	**$ 24**	$ 2
HFT derivatives	**226**	84	**226**	84
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 250**	$ 86	**$ 250**	$ 86

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, 2021, there were no outstanding cash flow hedges.

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

For the	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
millions of Canadian dollars	**Interest Rate Hedge**	Foreign exchange forwards	**Interest Rate Hedge**	Foreign exchange forwards
Realized loss in operating revenue – regulated	**$ -**	$ -	**$ -**	$ (2)
Realized gain in interest expense, net	**1**	-	**1**	-
Total gains (losses) in net income	**$ 1**	-	**$ 1**	$ (2)

As at	**September 30 2021**	December 31 2020
millions of Canadian dollars	**Interest Rate Hedge**	Interest Rate Hedge
Total unrealized gain in AOCI – net of tax	**$ 18**	$ 1

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 transactions settle.

Regulatory Deferral

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

For the millions of Canadian dollars	Three months ended September 30 **2021**		2020	
	Commodity swaps and forwards	**Foreign exchange forwards**	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ 10**	**$ 11**	$ 9	$ (2)
Unrealized gain (loss) in regulatory liabilities	**177**	**3**	11	(10)
Realized gain in regulatory assets	**(1)**	**-**	(1)	-
Realized loss in regulatory liabilities	**1**	**-**	3	-
Realized (gain) loss in inventory (1)	**(4)**	**-**	3	-
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(13)**	**-**	8	-
Total change in derivative instruments	**$ 170**	**$ 14**	$ 33	$ (12)

(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.

For the millions of Canadian dollars	Nine months ended September 30 **2021**		2020	
	Commodity swaps and forwards	**Foreign exchange forwards**	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ 21**	**$ 8**	$ (41)	$ 3
Unrealized gain (loss) in regulatory liabilities	**264**	**(1)**	8	5
Realized gain in regulatory assets	**(3)**	**-**	-	-
Realized (gain) loss in regulatory liabilities	**(1)**	**-**	13	-
Realized (gain) loss in inventory (1)	**2**	**3**	6	(3)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(13)**	**4**	21	(3)
Total change in derivative instruments	**$ 270**	**$ 14**	$ 7	$ 2

(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.

Commodity Swaps and Forwards

As at September 30, 2021, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	2021 Purchases	2022-2023 Purchases
Natural Gas (Mmbtu)	9	30
Power (MWh)	-	3
Heavy fuel oil (bbls)	-	1
Coal (metric tonnes)	-	1

Foreign Exchange Swaps and Forwards

As at September 30, 2021, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulated deferral that are expected to settle as outlined below:

	2021	2022-2023
Foreign exchange contracts (millions of US dollars)	$ 81	$ 250
Weighted average rate	1.2927	1.2822
% of USD requirements	104%	56%

The Company reassesses foreign exchange forecasted periodically and will enter into additional hedges or unwind existing hedges, as required.

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas, as well as power and natural gas swaps, forwards and futures, to economically hedge those physical contracts. These derivatives are all considered HFT.

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

For the millions of Canadian dollars	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Power swaps and physical contracts in non-regulated operating revenues	**$ 1**	$ (1)	**$ 3**	$ (1)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(236)**	(186)	**(229)**	36
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**-**	1	**1**	(3)
	$ (235)	$ (186)	**$ (225)**	$ 32

As at September 30, 2021, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2021	2022	2023	2024	2025
Natural gas purchases (Mmbtu)	118	196	83	54	26
Natural gas sales (Mmbtu)	137	184	70	21	2
Power purchases (MWh)	-	1	-	-	-
Power sales (MWh)	-	1	-	-	-

Other Derivatives

As at September 30, 2021, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and foreign exchange forwards in place to manage cash flow risk associated with forecasted US dollar cash inflows. The equity derivative hedges the return on 2.8 million shares and extends until December of 2021. The foreign exchange forwards have a combined notional amount of $56 million USD and expire in 2021.

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

For the millions of Canadian dollars	Three months ended September 30 **2021**			2020
	Foreign Exchange Forwards	**Equity Derivatives**	Foreign Exchange Forwards	Equity Derivatives
Unrealized gain in OM&G	**$ -**	**$ 3**	$ -	$ 4
Unrealized gain (loss) in other income, net	**(5)**	**-**	5	-
Realized gain in other income, net	**4**	**-**	-	-
Total gains (losses) in net income	**$ (1)**	**$ 3**	$ 5	$ 4

For the millions of Canadian dollars	Nine months ended September 30 **2021**			2020
	Foreign Exchange Forwards	**Equity Derivatives**	Foreign Exchange Forwards	Equity Derivatives
Unrealized gain (loss) in OM&G	**$ -**	**$ 9**	$ -	$ (3)
Unrealized gain (loss) in other income, net	**(11)**	**-**	9	-
Realized gain (loss) in other income, net	**13**	**-**	(4)	-
Total gains (losses) in net income	**$ 2**	**$ 9**	$ 5	$ (3)

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, foreign exchange 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, 2021, the Company had $121 million (December 31, 2020 - $123 million) in financial assets considered to be past due, which had been outstanding for an average 64 days. The fair value of these financial assets was $97 million (December 31, 2020 - $101 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 Canadian dollars	**September 30 2021**	December 31 2020
Cash collateral provided to others	**$ 189**	$ 69
Cash collateral received from others	**165**	6

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, 2021, the total fair value of derivatives in a liability position, was $714 million (December 31, 2020 – $338 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.

15. 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 14), 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				**September 30, 2021**
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**$ -**	**$ 69**	**$ -**	**$ 69**
Power purchases	**109**	**-**	**-**	**109**
Natural gas purchases and sales	**37**	**19**	**-**	**56**
Heavy fuel oil purchases	**2**	**19**	**-**	**21**
Foreign exchange forwards	**-**	**6**	**-**	**6**
	148	**113**	**-**	**261**
HFT derivatives				
Power swaps and physical contracts	**12**	**9**	**7**	**28**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**(1)**	**29**	**9**	**37**
	11	**38**	**16**	**65**
Other derivatives				
Foreign exchange forwards	**-**	**4**	**-**	**4**
Equity derivatives	**9**	**-**	**-**	**9**
	9	**4**	**-**	**13**
Total assets	**168**	**155**	**16**	**339**
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	**12**	**-**	**-**	**12**
Natural gas purchases and sales	**-**	**4**	**-**	**4**
Foreign exchange forwards	**-**	**9**	**-**	**9**
	12	**13**	**-**	**25**
HFT derivatives				
Power swaps and physical contracts	**8**	**8**	**9**	**25**
Natural gas swaps, futures, forwards and physical contracts	**29**	**204**	**431**	**664**
	37	**212**	**440**	**689**
Total liabilities	**49**	**225**	**440**	**714**
Net assets (liabilities)	**$ 119**	**$ (70)**	**$ (424)**	**$ (375)**

As at				December 31, 2020
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Interest rate hedge	$ 1	$ -	$ -	$ 1
	1	-	-	1
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	9	-	-	9
Natural gas purchases and sales	2	1	-	3
Heavy fuel oil purchases	-	2	-	2
	11	3	-	14
HFT derivatives				
Power swaps and physical contracts	3	2	2	7
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	48	12	61
	4	50	14	68
Other derivatives				
Foreign exchange forwards	-	15	-	15
	-	15	-	15
Total assets	16	68	14	98
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	4	-	4
Power purchases	33	-	-	33
Heavy fuel oil purchases	3	3	-	6
Natural gas purchases and sales	-	2	-	2
Foreign exchange forwards	-	17	-	17
	36	26	-	62
HFT derivatives				
Power swaps and physical contracts	4	2	1	7
Natural gas swaps, futures, forwards and physical contracts	1	10	257	268
	5	12	258	275
Other derivatives				
Equity derivatives	1	-	-	1
	1	-	-	1
Total liabilities	42	38	258	338
Net assets (liabilities)	$ (26)	$ 30	$ (244)	$ (240)

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2021 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	$ 1	$ 5	$ 6
Total realized and unrealized losses included in non-regulated operating revenues	6	4	10
Balance, September 30, 2021	**$ 7**	**$ 9**	**$ 16**

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2021 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	$ 3	$ 313	$ 316
Total realized and unrealized gains included in non-regulated operating revenues	6	118	124
Balance, September 30, 2021	**$ 9**	**$ 431**	**$ 440**

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2021 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	$ 2	$ 12	$ 14
Total realized and unrealized losses included in non-regulated operating revenues	5	(3)	2
Balance, September 30, 2021	**$ 7**	**$ 9**	**$ 16**

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2021 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	$ 1	$ 257	$ 258
Total realized and unrealized gains included in non-regulated operating revenues	8	174	182
Balance, September 30, 2021	**$ 9**	**$ 431**	**$ 440**

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; 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. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

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, 2021	
millions of Canadian dollars		Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average (1)
Assets						
HFT derivatives – Power swaps and physical contracts	$	7	Modelled pricing	Third-party pricing	$34.50 - $186.35	$149.06
				Probability of default	0.01% - 16.42%	0.74%
				Discount rate	0.01% - 1.01%	0.10%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		9	Modelled pricing	Third-party pricing	$2.26 - $11.31	$4.77
				Probability of default	0.01% - 5.02%	0.24%
				Discount rate	0.00% - 11.67%	0.22%
Total assets	**$**	**16**				
Liabilities						
HFT derivatives – Power swaps and physical contracts	$	6	Modelled pricing	Third-party pricing	$1.13 - $185.60	$139.33
				Own credit risk	0.01% - 16.42%	0.16%
				Discount rate	0.01% - 1.01%	0.10%
		3	Modelled pricing	Third-party pricing	$42.55 - $186.35	$139.00
				Correlation factor	100% - 100%	100.00%
				Own credit risk	0.01% - 0.03%	0.01%
				Discount rate	0.01% - 0.35%	0.09%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		409	Modelled pricing	Third-party pricing	$1.95 - $23.46	$11.84
				Own credit risk	0.01% - 5.02%	0.09%
				Discount rate	0.00% - 14.77%	1.34%
		22	Modelled pricing	Third-party pricing	$4.09 - $23.90	$17.84
				Basis adjustment	$0.42 - $1.20	$0.52
				Own credit risk	0.01% - 4.56%	0.02%
				Discount rate	0.00% - 0.93%	0.08%
Total liabilities	**$**	**440**				
Net liabilities	**$**	**(424)**				

(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 Canadian dollars		Carrying Amount		Fair Value		Level 1		Level 2		Level 3		Total
September 30, 2021	**$**	**14,436**	**$**	**16,509**	**$**	**-**	**$**	**16,056**	**$**	**453**	**$**	**16,509**
December 31, 2020	$	13,721	$	16,487	$	-	$	16,020	$	467	$	16,487

The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations. An after-tax foreign currency loss of $35 million was recorded in Other Comprehensive Income for the three months ended September 30, 2021 (2020 – $34 million after tax gain) and $1 million for the nine months ended September 30, 2021 (2020 – $41 million).

16. 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 $27 million for the three months ended September 30, 2021 (2020 - $27 million) and $91 million for the nine months ended September 30, 2021 (2020 - $82 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 $4 million for the three months ended September 30, 2021 (2020 - $2 million) and $14 million for the nine months ended September 30, 2021 (2020 - $13 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, 2021 and at December 31, 2020.

17. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars	**September 30 2021**	December 31 2020
Customer accounts receivable – billled	**$ 692**	$ 570
Customer accounts receivable – unbilled	**241**	286
Allowance for credit losses	**(24)**	(22)
Capitalized transportation capacity (1)	**102**	200
Income tax receivable	**11**	11
Prepaid expenses	**92**	50
Other	**258**	138
	$ 1,372	$ 1,233

(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.

18. 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, Dominica and Grand Bahama Island. For details of the Company's employee benefit plan, refer to note 21 in Emera's 2020 annual audited consolidated financial statements and note 1 "Use of Management Estimates – Pension and Other Post-Retirement Employee Benefits".

Emera's net periodic benefit cost included the following:

For the	Three months ended September 30		Nine months ended September 30	
millions of Canadian dollars	**2021**	2020	**2021**	2020
Defined benefit pension plans				
Service cost	**$ 10**	**$** 11	$ **32**	**$** 35
Non-service cost				
Interest cost	**16**	21	**50**	64
Expected return on plan assets	**(33)**	(34)	**(99)**	(107)
Current year amortization of:				
Actuarial losses	**4**	4	**13**	11
Past service gains	**-**	(1)	**-**	(1)
Regulatory asset	**8**	6	**21**	20
Total non-service costs	**(5)**	(4)	**(15)**	(13)
Total defined benefit pension plans	**5**	7	**17**	22
Non-pension benefit plans				
Service cost	**1**	1	**4**	3
Non-service cost				
Interest cost	**2**	2	**6**	8
Expected return on plan assets	**(1)**	-	**(2)**	(1)
Current year amortization of regulatory asset	**2**	-	**4**	-
Total non-service costs	**3**	2	**8**	7
Total non-pension benefit plans	**4**	3	**12**	10
Total defined benefit plans	**$ 9**	$ 10	**$ 29**	$ 32

Emera's pension and non-pension contributions related to these defined-benefit plans for the three months ended September 30, 2021 were $24 million (2020 – $20 million), and for the nine months ended September 30, 2021 were $53 million (2020 – $50 million). Annual employer contributions to the defined benefit pension plans are estimated to be $41 million for 2021. Emera's contributions related to these defined contribution plans for the three months ended September 30, 2021 were $10 million (2020 – $12 million) and $29 million (2020 – $31 million) for the nine months ended September 30, 2021.

19. 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 2020 annual audited consolidated financial statements, and below for 2021 short-term debt financing activity.

Recent Significant Financing Activity by Segment

Florida Electric Utility

On May 25, 2021, TEC established a commercial paper program. Amounts available under the commercial paper program may be borrowed, repaid and reborrowed with the aggregate amount of the notes outstanding at any time not to exceed $800 million USD. The full amount of commercial paper issued is backed by TEC's credit facility and results in an equal amount of its credit facility being considered drawn and unavailable.

Using proceeds from the $800 million USD senior notes issuance (refer to note 20), on March 23, 2021, TEC repaid its $300 million USD non-revolving term loan. TEC also repaid its $150 million USD accounts receivable collateralized borrowing facility and the agreement subsequently matured and terminated on March 22, 2021.

20. LONG-TERM DEBT

For details regarding long-term debt, refer to note 25 in Emera's 2020 annual audited consolidated financial statements, and below for 2021 long-term debt financing activity.

Recent Significant Financing Activity by Segment

Florida Electric Utility

On May 15, 2021, TEC repaid its $278 million USD, 5.4 per cent notes upon maturity. The notes were repaid using existing credit facilities.

On March 18, 2021, TEC completed an issuance of $800 million USD senior notes. The issuance included $400 million USD senior notes that bear interest at a rate of 2.40 per cent with a maturity date of March 15, 2031 and $400 million USD senior notes that bear interest at a rate of 3.45 per cent with a maturity date of March 15, 2051.

Gas Utilities and Infrastructure

On July 16, 2021, Brunswick Pipeline extended the maturity date of its $250 million credit facility from May 17, 2023 to June 30, 2025. There were no other significant changes in commercial terms from the prior agreement.

On March 25, 2021, NMGC entered into a $100 million USD unsecured, non-revolving credit facility with a maturity date of September 23, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the LIBOR, prime rate, or the federal funds rate, plus a margin.

On February 5, 2021, NMGC completed an issuance of $220 million USD senior notes. The issuance included $70 million USD senior notes that bear interest at a rate of 2.26 per cent with a maturity date of February 5, 2031, $65 million USD senior notes that bear interest at a rate of 2.51 per cent and with a maturity date of February 5, 2036, and $85 million USD senior notes that bear interest at a rate of 3.34 per cent with a maturity date of February 5, 2051. Proceeds from this issuance were used to repay a $200 million USD note due in 2021, which was classified as long-term debt at December 31, 2020.

Other

On July 23, 2021, Emera extended the maturity date of its $900 million unsecured committed revolving credit facility from June 30, 2024 to June 30, 2026. There were no other significant changes in commercial terms from the prior agreement.

On June 4, 2021 Emera US Finance LP completed an issuance of $750 million USD senior notes. The issuance included $450 million USD senior notes that bear interest at a rate of 2.64 per cent with a maturity date of June 15, 2031 and $300 million USD senior notes that bear interest at a rate of 0.83 per cent with a maturity date of June 15, 2024. The USD senior notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary.

As a result of the $750 million USD senior notes issuance discussed above, on June 15, 2021, Emera US Finance LP repaid its previously outstanding $750 million USD senior notes on maturity.

21. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2021, 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 Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Transportation (1)	$ 185	485	406	348	311	2,806	$ 4,541
Purchased power (2)	68	227	221	238	237	2,176	3,167
Fuel, gas supply and storage	303	340	72	45	40	24	824
Capital Projects	473	159	95	6	1	-	734
Long-term service agreements (3)	36	64	68	48	32	90	338
Equity investment commitments (4)	-	240	-	-	-	-	240
Leases and other (5)	3	16	16	15	8	120	178
Demand side management	10	45	-	-	-	-	55
	$ 1,078	$ 1,576	$ 878	$ 700	$ 629	$ 5,216	$ 10,077

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $144 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(2) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.

(3) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.

(4) Emera has a commitment to make equity contributions to the LIL.

(5) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

Nalcor continues to advance towards construction completion of the Lower Churchill projects (including Muskrat Falls and LIL) with final commissioning targeted for Q1 2022. Three of four generators at Muskrat Falls are completed and available for service, the first in Q3 2020, the second in Q2 2021, and the third in Q3 2021.

The UARB approved assessment for 2021 is approximately $172 million. This is subject to a holdback of up to $10 million, that is dependent upon the timing of commencement of the NS Block and NSPML has deferred collection of $23 million in depreciation expense. Nalcor has commenced delivery of the NS Block on August 15, 2021 and the NS Block will be delivered over the next 35 years pursuant to the agreements with Nalcor. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related interruptions in supply with any resultant delivery shortfalls being delivered at a later date. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment.

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. As part of NSPI's 2020-2022 fuel stability plan, rates have been set to include $164 million and $162 million for 2021 and 2022, respectively. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Once Muskrat Falls and LIL have achieved full power, 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 commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Leases and 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. For more information, refer to note 27 of Emera's 2020 annual audited consolidated financial statements.

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. On May 17, 2021, the ad hoc Committee issued (i) a decision continuing the stay of enforcement of the Second Award until the committee renders its decision on Guatemala's application for annulment and (ii) an order with dates for briefings on the annulment and a hearing commencing July 27, 2022. Guatemala filed its Memorial on Annulment on August 25, 2021. TGH's Counter-Memorial on Annulment is due on December 8, 2021. To date, the total of the Second Award, with interest, is approximately $60 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, 2021, TEC has estimated its financial liability to be $22 million ($17 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

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 14 and note 15.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management.

Public Health Risk

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company, including causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital investments, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business.

The extent of the evolving COVID-19 pandemic and its future impact on the Company is uncertain. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat. The Company's top priority continues to be the health and safety of its customers and employees.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, with an increasing amount of the Company's net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams and capital investments, and on net income earned outside of Canada. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in AOCI.

Liquidity and Capital Market Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions including those related to public health threats, such as the COVID-19 pandemic.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increased borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital investments, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Interest rates may be impacted by market disruptions related to public health threats, including the COVID-19 pandemic.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Commodity Price Risk

The Company's utility fuel supply is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments are all used to manage and mitigate this risk. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

Regulated Utilities

A large portion of the Company's utility fuel supply comes from international suppliers and therefore may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated utilities have adopted and implemented fuel adjustment mechanisms which has further helped manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Emera Energy Marketing and Trading

Emera Energy has employed further measures to manage commodity risk. The majority of Emera's portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets, in the event of an operational issue or counterparty default.

To measure commodity price risk exposure, Emera employs a number of controls and processes, including an estimated value-at-risk ("VaR") analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

D. Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2020 audited annual consolidated financial statements.

The Company has standby letters of credit and surety bonds in the amount of $62 million USD (December 31, 2020 - $55 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.

NSPI has issued guarantees in the amount of $28 million USD (December 31, 2020 - $18 million USD) on behalf of its subsidiary, NS Power Energy Marketing Incorporated ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers. The guarantees have terms of varying lengths and will be renewed as required.

On October 28, 2021, NSPI issued an additional guarantee of $85 million USD on behalf of its subsidiary NSPEMI, relating to a 15-year natural gas transportation commitment.

22. CUMULATIVE PREFERRED STOCK

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

	Issued and Outstanding		Net Proceeds
Balance, December 31, 2020	41,000,000	$	1,004
Issuance of First Preferred Shares Series J	8,000,000		196
Issuance of First Preferred Shares Series L	9,000,000		222
Balance, September 30, 2021	**58,000,000**	**$**	**1,422**

First Preferred Shares, Series J

On April 6, 2021, Emera issued 8 million, 4.25 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series J ("First Preferred Shares, Series J") at $25.00 per share for gross proceeds of $200 million ($196 million, net of after-tax issuance costs).

First Preferred Shares, Series L

On September 24, 2021, Emera issued 9 million, 4.60 per cent Cumulative Redeemable First Preferred Shares, Series L ("First Preferred Shares, Series L") at $25.00 per share for gross proceeds of $225 million ($222 million, net of after-tax issuance costs).

Characteristics of the First Preference Shares are as follows:

First Preference Shares (1)(2)	Initial Yield (%)	Annual Dividend ($)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a one for one basis
Minimum rate reset (3)(4)						
Series J	4.25	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate (5)						
Series L	4.60	1.1500		November 15, 2026	25.00	

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.
(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.
(3) On the conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus 3.28 per cent provided that such rate shall not be less than 4.25 per cent.
(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Floating Rate First Preference Shares, Series K of the Company. The floating quarterly dividend rate on the Series K shares will be equal to the sum of the 90-day T-Bill rate plus 3.28 per cent.
(5) First Preferred Shares, Series L are redeemable at $26.00 on or after November 15, 2026 to November 15, 2027, decreasing $0.25 each year until November 15, 2030 and $25.00 per share thereafter.

First Preference Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends will be deducted on the Consolidated Statements of Income immediately before arriving at "Net earnings attributable to common shareholders" and will be shown on the Consolidated Statement of Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

23. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Nine months ended September 30 **2021**	 2020
Changes in non-cash working capital:		
Inventory	**$ (76)**	$ (3)
Receivables and other current assets	**(223)**	115
Accounts payable	**282**	(42)
Other current liabilities	**88**	69
Total non-cash working capital	**$ 71**	$ 139
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 157**	$ 140
Increase in accrued capital expenditures	**$ (1)**	$ 23

24. 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 Maritime Link. Thus, Emera records the Maritime Link 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, 2021**		December 31, 2020	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 542**	**$ 10**	$ 547	$ 16

25. COMPARATIVE INFORMATION

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

26. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through November 9, 2021, the date the financial statements were issued.