

EMERA INCORPORATED

Consolidated

Financial Statements

December 31, 2020 and 2019

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgments and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and with the standards of the Public Company Accounting Oversight Board. Ernst & Young LLP has full and free access to the Audit Committee.

February 16, 2021

"Scott Balfour"
President and Chief Executive Officer

"Gregory Blunden"
Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the Consolidated Balance Sheets as at December 31, 2020 and 2019, and the Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2020 and 2019, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

Accounting for the effects of rate regulation

Key Audit Matter

As disclosed in note 7 of the consolidated financial statements, the Company has \$1.6 billion in regulatory assets and \$2.0 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including property, plant and equipment, operating revenues and expenses, income taxes, and depreciation expense.

*How Our Audit
Addressed the Key
Audit Matter*

Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and recovery on costs incurred, of the disallowance of part of the cost of recently completed property, plant and equipment and construction work in progress, or of the probable refund to customers through future rates.

We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value measurement and disclosure of derivative financial instruments

Key Audit Matter

Held-for-trading ("HFT") derivative assets of \$152 million and liabilities of \$359 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized \$200 million in realized and unrealized gains during the year with respect to HFT derivatives.

Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials, the Company's own credit risk and discount rates. These assumptions have a significant impact on the fair value of the HFT derivatives.

*How Our Audit
Addressed the Key
Audit Matter*

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves, credit metrics and discount rates used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the fair value hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the fair value of derivatives.

Other information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's reports thereon, in the Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Ivan Chittenden.

/s/ Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 16, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion on the Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of Emera Incorporated (the "Company") as of December 31, 2020 and 2019, the related Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and the related notes and schedules (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2020 and 2019, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2020, in conformity with United States generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the effects of rate regulation

Description of the Matter

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How We Addressed the Matter in Our Audit

We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

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/s/ Ernst & Young LLP
Chartered Professional Accountants

We have served as the Company's auditor since 1998.

Halifax, Canada
February 16, 2021

Emera Incorporated **Consolidated Statements of Income**

For the
millions of Canadian dollars (except per share amounts)

Year ended December 31
2020 2019

Operating revenues		
Regulated electric	\$ 4,442	\$ 4,769
Regulated gas	1,034	1,081
Non-regulated	30	261
Total operating revenues (note 6)	5,506	6,111

Operating expenses		
Regulated fuel for generation and purchased power (notes 17 and 19)	1,420	1,609
Regulated cost of natural gas	293	350
Non-regulated fuel for generation and purchased power	4	66
Operating, maintenance and general	1,419	1,464
Provincial, state, and municipal taxes	317	342
Depreciation and amortization	881	903
Impairment charges	25	34
Total operating expenses	4,359	4,768

Income from operations	1,147	1,343
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Income from equity investments (note 8)	149	154
Other income, net (note 9)	708	12
Interest expense, net	679	738
Income before provision for income taxes	1,325	771

Income tax expense (note 10)	341	61
Net income	984	710

Non-controlling interest in subsidiaries	1	2
Preferred stock dividends	45	45
Net income attributable to common shareholders	\$ 938	\$ 663

Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	248	240
Diluted	248	240

Earnings per common share (note 12)		
Basic	\$ 3.78	\$ 2.76
Diluted	\$ 3.78	\$ 2.76

Dividends per common share declared	\$ 2.4750	\$ 2.3750
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The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated

Consolidated Statements of Comprehensive Income

For the millions of Canadian dollars	Year ended December 31	
	2020	2019
Net income	\$ 984	\$ 710
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	(201)	(402)
Unrealized gains on net investment hedges (2) (3)	26	78
Cash flow hedges		
Net derivative gains	-	3
Less: reclassification adjustment for losses included in income	2	3
Net effects of cash flow hedges	2	6
Net change in unrecognized pension and post-retirement benefit obligation (4)	(1)	74
Other comprehensive income (loss) (5)	(174)	(244)
Comprehensive income (loss)	810	466
Comprehensive income (loss) attributable to non-controlling interest	1	1
Comprehensive Income (loss) of Emera Incorporated	\$ 809	\$ 465

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

- 1) Net of tax recovery of \$1 million (2019 - nil) for the year ended December 31, 2020.
- 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 expense of \$4 million (2019 - \$1 million tax expense) for the year ended December 31, 2020.
- 4) Net of tax recovery of \$1 million (2019 - \$9 million expense) for the year ended December 31, 2020.
- 5) Net of tax expense of \$2 million (2019 - \$10 million expense) for the year ended December 31, 2020.

Emera Incorporated

Consolidated Balance Sheets

As at millions of Canadian dollars	December 31 2020	December 31 2019
Assets		
Current assets		
Cash and cash equivalents	\$ 220	\$ 222
Restricted cash (note 32)	34	51
Inventory (note 14)	453	467
Derivative instruments (notes 15 and 16)	73	54
Regulatory assets (note 7)	165	121
Receivables and other current assets (note 18)	1,233	1,486
Assets held for sale (note 4)	-	85
	2,178	2,486
Property, plant and equipment , net of accumulated depreciation and amortization of \$8,714 and \$8,317, respectively (note 20)	19,535	18,167
Other assets		
Deferred income taxes (note 10)	209	186
Derivative instruments (notes 15 and 16)	25	33
Regulatory assets (note 7)	1,419	1,431
Net investment in direct financing lease (note 19)	475	473
Investments subject to significant influence (note 8)	1,346	1,312
Goodwill (note 22)	5,720	5,835
Other long-term assets	327	300
Assets held for sale (note 4)	-	1,619
	9,521	11,189
Total assets	\$ 31,234	\$ 31,842

Emera Incorporated **Consolidated Balance Sheets – Continued**

As at millions of Canadian dollars	December 31 2020	December 31 2019
Liabilities and Equity		
Current liabilities		
Short-term debt (note 23)	\$ 1,625	\$ 1,537
Current portion of long-term debt (note 25)	1,382	501
Accounts payable	1,148	1,118
Derivative instruments (notes 15 and 16)	251	268
Regulatory liabilities (note 7)	129	295
Other current liabilities (note 24)	340	333
Liabilities associated with assets held for sale (note 4)	-	114
	4,875	4,166
Long-term liabilities		
Long-term debt (note 25)	12,339	13,679
Deferred income taxes (note 10)	1,629	1,285
Derivative instruments (notes 15 and 16)	87	102
Regulatory liabilities (note 7)	1,832	1,886
Pension and post-retirement liabilities (note 21)	453	460
Other long-term liabilities (notes 8 and 26)	781	764
Long-term liabilities associated with assets held for sale (note 4)	-	899
	17,121	19,075
Equity		
Common stock (note 11)	6,705	6,216
Cumulative preferred stock (note 28)	1,004	1,004
Contributed surplus	79	78
Accumulated other comprehensive income (loss) (note 13)	(79)	95
Retained earnings	1,495	1,173
Total Emera Incorporated equity	9,204	8,566
Non-controlling interest in subsidiaries (note 29)	34	35
Total equity	9,238	8,601
Total liabilities and equity	\$ 31,234	\$ 31,842

Commitments and contingencies (note 27)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"

Chair of the Board

"Scott Balfour"

President and Chief Executive Officer

Emera Incorporated

Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31	
	2020	2019
Operating activities		
Net income	\$ 984	\$ 710
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	899	911
Income from equity investments, net of dividends	(76)	(83)
Allowance for equity funds used during construction	(45)	(21)
Deferred income taxes, net	381	125
Net change in pension and post-retirement liabilities	(23)	(17)
Regulated fuel adjustment mechanism	(94)	(46)
Net change in fair value of derivative instruments	(36)	(39)
Net change in regulatory assets and liabilities	(87)	44
Net change in capitalized transportation capacity	52	(55)
Impairment charges	25	34
Gain on sale, excluding transaction costs	(603)	-
Other operating activities, net	43	35
Changes in non-cash working capital (note 30)	217	(73)
Net cash provided by operating activities	1,637	1,525
Investing activities		
Additions to property, plant and equipment	(2,623)	(2,495)
Proceeds from dispositions (note 4)	1,401	875
Other investing activities	(2)	3
Net cash used in investing activities	(1,224)	(1,617)
Financing activities		
Change in short-term debt, net	385	413
Proceeds from short-term debt with maturities greater than 90 days	399	-
Repayment of short-term debt with maturities greater than 90 days	(688)	-
Proceeds from long-term debt, net of issuance costs	428	1,066
Retirement of long-term debt	(513)	(1,103)
Net repayments under committed credit facilities	(203)	(118)
Issuance of common stock, net of issuance costs	285	203
Dividends on common stock	(409)	(378)
Dividends on preferred stock	(45)	(45)
Other financing activities	(11)	(24)
Net cash (used in) provided by financing activities	(372)	14
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	(61)	(20)
Net decrease in cash, cash equivalents, restricted cash and assets held for sale	(20)	(98)
Cash, cash equivalents, restricted cash, and assets held for sale, beginning of year	274	372
Cash, cash equivalents, and restricted cash, end of year	\$ 254	\$ 274
Cash, cash equivalents, restricted cash and assets held for sale consists of:		
Cash	\$ 220	\$ 222
Restricted cash	34	51
Assets held for sale	-	1
Cash, cash equivalents and restricted cash	\$ 254	\$ 274

Supplementary Information to Consolidated Statements of Cash Flows (note 30)

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

Emera Incorporated **Consolidated Statements of Changes in Equity**

	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) (1)	Retained Earnings	Non- Controlling Interest	Total Equity
millions of Canadian dollars							
Balance, December 31, 2019	\$ 6,216	\$ 1,004	\$ 78	\$ 95	\$ 1,173	\$ 35	\$ 8,601
Net income of Emera incorporated	-	-	-	-	983	1	984
Other comprehensive loss, net of tax expense of \$2 million	-	-	-	(174)	-	-	(174)
Dividends declared on preferred stock (note 28)	-	-	-	-	(45)	-	(45)
Dividends declared on common stock (\$2.4750/share)	-	-	-	-	(609)	-	(609)
Common stock issued under purchase plan	215	-	-	-	-	-	215
Issuance of common stock, net of after-tax issuance costs	251	-	-	-	-	-	251
Senior management stock options exercised	20	-	(1)	-	-	-	19
Adoption of credit losses accounting standard (note 2)	-	-	-	-	(7)	-	(7)
Other	3	-	2	-	-	(2)	3
Balance, December 31, 2020	\$ 6,705	\$ 1,004	\$ 79	\$ (79)	\$ 1,495	\$ 34	\$ 9,238
Balance, December 31, 2018	\$ 5,816	\$ 1,004	\$ 84	\$ 338	\$ 1,075	\$ 41	\$ 8,358
Net income	-	-	-	-	708	2	710
Other comprehensive loss, net of tax expense of \$10 million	-	-	-	(243)	-	(1)	(244)
Dividends declared on preferred stock (note 28)	-	-	-	-	(45)	-	(45)
Dividends declared on common stock (\$2.3750/share)	-	-	-	-	(565)	-	(565)
Common stock issued under purchase plan	195	-	-	-	-	-	195
Issuance of common stock, net of after-tax issuance costs	99	-	-	-	-	-	99
Senior management stock options exercised	104	-	(7)	-	-	-	97
Issuance of preferred shares of GBPC, net of issuance costs (note 29)	-	-	-	-	-	14	14
Redemption of preferred shares of GBPC (note 29)	-	-	-	-	-	(19)	(19)
Other	2	-	1	-	-	(2)	1
Balance, December 31, 2019	\$ 6,216	\$ 1,004	\$ 78	\$ 95	\$ 1,173	\$ 35	\$ 8,601

(1) Accumulated Other Comprehensive Income (Loss) ("AOCI") ("AOCL")

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

Emera Incorporated
Notes to the Consolidated Financial Statements
As at December 31, 2020 and 2019

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 December 31, 2020, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility, serving approximately 792,500 customers 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, serving approximately 529,000 customers; 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 45.6 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. Nalcor continues to work towards commissioning the LIL. In response to the COVID-19 pandemic, on March 17, 2020 Nalcor announced that it had paused construction activities at the Muskrat Falls site and resumed work in May 2020. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing project commissioning in 2021. Refer to note 27 for further details.
- 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, serving approximately 131,000 customers;
 - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 customers;
 - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), a vertically integrated regulated electric utility on the island of Dominica, serving approximately 34,000 customers; 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. Refer to note 4 for further information.

- Gas Utilities and Infrastructure, which includes:
 - Peoples Gas System (“PGS”), a regulated gas distribution utility, serving approximately 426,000 customers across Florida;
 - New Mexico Gas Company, Inc. (“NMGC”), a regulated gas distribution utility, serving approximately 540,000 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, which 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 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.
 - Emera Reinsurance Limited, a captive insurance company providing insurance and reinsurance to Emera and certain affiliates, to enable more cost-efficient management of risk and deductible levels across Emera;
 - Emera US Finance LP (“Emera Finance”) and TECO Finance, Inc. (“TECO Finance”), financing subsidiaries of Emera;
 - Emera US Holdings Inc., a wholly owned holding company for certain of Emera’s assets located in the United States; and
 - other investments.

In 2019, the Company completed the sale of assets previously included in the Other segment, including Emera Energy’s New England Gas Generating (“NEGG”) and Bayside facilities, and Emera Utility Services (“EUS”) equipment and inventory.

In 2020, the outbreak of the novel strain of coronavirus, specifically identified as COVID-19, has 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 as of and for the year ended December 31, 2020 were not materially impacted by COVID-19. However, it is not possible to reliably estimate the length and severity of the COVID-19 pandemic and the impact on the financial results and condition of the Company in future periods.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles (“USGAAP”). In the opinion of management, these consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera.

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

Principles of Consolidation

The consolidated financial statements of Emera include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. Refer to note 32 for further details. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for variable interest entities in which Emera is not the primary beneficiary.

The Company performs ongoing analysis to assess whether it holds any VIEs or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. 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.

Intercompany balances and transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues. An offset is recorded to property, plant and equipment, regulatory assets, regulated fuel for generation and purchased power, or operating, maintenance and general ("OM&G"), depending on the nature of the transaction.

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.

During the year ended December 31, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis these unfavourable impacts have not had a material financial impact to net earnings primarily due to a favourable change to the mix of sales across customer classes. Lower commercial and industrial sales have been partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather in 2020, particular in Florida, has further reduced the consolidated impact. Emera's utilities provide essential services and continue to operate and meet customer demand. Governments world-wide have implemented measures intended to address the pandemic. These measures include travel and transportation restrictions, quarantines, physical distancing, closures of commercial spaces and industrial facilities, shutdowns, shelter-in-place orders and other health measures. These measures are adversely impacting global, national and local economies. Global equity markets have experienced significant volatility. Governments and central banks are implementing measures designed to stabilize economic conditions. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments are required for the year ended December 31, 2020. Refer to Asset Impairment: Long-Lived Assets, Asset Impairment: Goodwill and Employee Benefits below for additional details on areas that could be more significantly impacted.

The extent of 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.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. The rates are designed to recover prudently incurred costs of providing the regulated products or services and provide an opportunity for a reasonable rate of return on the equity invested or assets, as applicable (refer to note 7 for additional details).

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to Canadian dollars at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Assets and liabilities of foreign operations whose functional currency is not the Canadian dollar are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average exchange rate in effect for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCI.

The Company designates certain United States dollar denominated debt held in Canadian dollar functional currency companies as hedges of net investments in United States dollar denominated foreign operations. The change in the carrying amount of these investments, measured at the exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

Revenue Recognition

Regulated Electric Revenue

Electric revenues, including energy charges, demand charges, basic facilities charges and clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the electricity. Electric revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the respective regulator and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of megawatt hour ("MWh") delivered to customers at the established rate expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

Regulated Gas Revenue

Gas revenues, including energy charges, demand charges, basic facilities charges and applicable clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when gas is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the gas. Gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the distribution and sale of gas are recognized at rates approved by the respective regulator and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly. At the end of each reporting period, the gas delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of therms delivered to customers at the established rate expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of usage, weather, and inter-period changes to customer classes.

Non-regulated Revenue

Marketing and trading margins are comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management revenues. Revenues are recorded when obligations under terms of a contract are satisfied and are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

Energy sales are recognized when obligations under the terms of the contracts are satisfied, which is when electricity is delivered to customers over time.

Capacity payments are recognized when obligations under the terms of a contract are satisfied, which is as the plants stand ready to deliver electricity to customers. Revenues related to capacity payments are recognized at rates determined through an auction process held annually, three years in advance, through the forward capacity market.

Other non-regulated revenues are recorded when obligations under terms of a contract are satisfied.

Other

Sales, value add, and other taxes, except for gross receipts taxes discussed below, collected by the Company concurrent with revenue-producing activities are excluded from revenue.

Leases

The Company determines whether a contract contains a lease at inception by evaluating if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Emera has leases with independent power producers and other utilities with annual requirements to purchase wind and hydro energy over varying contract lengths that are classified as finance leases. These finance leases are not recorded on the Company's Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as "Regulated fuel for generation and purchased power" on the Consolidated Statements of Income.

Operating lease liabilities and right-of-use ("ROU") assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera's leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as "Operating, maintenance and general" on the Consolidated Statements of Income.

Where the Company is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that consists of the sum of the minimum lease payments and residual value (net of estimated executory costs and unearned income). The difference between the gross investment and the cost of the leased item is recorded as unearned income at the inception of the lease. Unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

For sales-type leases, the accounting is similar to the accounting for direct finance leases, however the difference between the fair value and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

Emera has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component.

Franchise Fees and Gross Receipts

Tampa Electric and PGS recover from customers certain costs incurred, on a dollar-for-dollar basis, through prices approved by the Florida Public Service Commission ("FPSC"). The amounts included in customers' bills for franchise fees and gross receipt taxes are included as "Regulated electric" and "Regulated gas" revenues in the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Provincial, state and municipal taxes".

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statements of Income.

Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property, plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income. Where a disposition of non-regulated property, plant and equipment occurs, gains and losses are included in income as the dispositions occur.

The cost of property, plant and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, asset retirement obligations ("ARO") and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and labour costs, along with other costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have a future economic benefit.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. For some of Emera's rate-regulated subsidiaries depreciation is calculated using the group remaining life method, which is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property. The service lives of regulated assets require the appropriate regulatory approval.

Intangible assets, which are included in "Property, plant and equipment" consist primarily of computer software and land rights. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the asset in each category. For some of Emera's rate-regulated subsidiaries, amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets. The service lives of regulated intangible assets require regulatory approval.

Goodwill

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of identifiable assets acquired and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment and is adjusted for the impact of foreign exchange. Under the applicable accounting guidance, goodwill is subject to assessment for impairment at the reporting unit level annually or if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. Refer to note 22 for further detail.

Income Taxes and Investment Tax Credits

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change is enacted unless required to be offset to a regulatory asset or liability by law or by order of the regulator. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to reflect the amount of deferred income tax asset expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned by Tampa Electric, PGS and NMGC on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by regulatory practices.

Tampa Electric, PGS, NMGC, BLPC and Domlec collect income taxes from customers based on current and deferred income taxes. NSPI, ENL and Brunswick Pipeline collect income taxes from customers based on income tax that is currently payable except for the deferred income taxes on certain regulatory balances specifically prescribed by the regulator. For the balance of regulated deferred income taxes, NSPI, ENL and Brunswick Pipeline recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets. GBPC is not subject to income taxes.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. Refer to note 10 for further details.

Derivatives and Hedging Activities

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. These physical and financial contracts are classified as held-for-trading ("HFT"). Collectively, these contracts and financial instruments are considered derivatives.

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception 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 creditworthy. Emera continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. 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 any changes in fair value are recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NMGC, NSPI and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. 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 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.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in fair value normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory and property, operating maintenance and general and plant and equipment, depending on the nature of the item being economically hedged. Transportation capacity arising as a result of marketing and trading derivative transactions is recognized as an asset in "Receivables and other current assets" and amortized over the period of the transportation contract term. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables and other current assets" and obligations to return cash collateral are recognized in "Accounts payable".

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition.

Receivables and Allowance for Credit Losses

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments may be conducted on new customers. Deposits are requested on accounts in accordance with the Company's policy. The Company also maintains provisions for expected credit losses, which are assessed on a regular basis.

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. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

The economic impact of COVID-19, in the service territories in which 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.

Inventory

Fuel and materials inventories are valued using the weighted-average cost method. These inventories are carried at the lower of weighted-average cost or net realizable value, unless evidence indicates that the weighted-average cost will be recovered in future customer rates.

Asset Impairment

Long-Lived Assets

Emera assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or sale of a business.

The review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value. The Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

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 December 31, 2020, there are no indications of impairment of Emera's long-lived assets. The impact of COVID-19 could cause the Company to impair long-lived assets in the future; however, 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.

Impairment charges of \$25 million (\$26 million after tax) were recognized on certain assets during the year ended December 31, 2020 and recorded in Impairment Charge in the Consolidated Income Statement. In 2019, as a result of Hurricane Dorian, Grand Bahama recognized an impairment of \$18 million USD which has been fully recovered through insurance.

Goodwill

Goodwill is not amortized but is subject to an annual assessment for impairment at the reporting unit level with interim impairment tests performed when impairment indicators are present. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Reporting units with similar characteristics are grouped for the purpose of determining impairment, if any, of goodwill. When assessing goodwill for impairment the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

If the Company performs the qualitative assessment and determines that it is more likely than not that its fair value is less than its carrying amount or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Management estimates the fair value of the reporting unit by using the income approach or a combination of the income and market approach. The income approach is applied using a discounted cash flow analysis which relies on management's best estimate of the reporting units' projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit's residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. When using the market approach, management estimates fair value based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions, valuation of the reporting unit's net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows and the fair value of debt. Adverse changes in assumptions described above could result in a future material impairment of the goodwill assigned to Emera's reporting units with goodwill. As part of the 2020 goodwill impairment assessment management considered the potential impacts of the COVID-19 pandemic on the future earnings of the reporting units.

As of December 31, 2020, \$5,649 million of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Qualitative assessments were performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded that it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required.

A GBPC goodwill impairment charge of \$30 million was recorded in 2019 due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. As of December 31, 2020, \$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. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions could result in a future impairment. Refer to note 22 for further details.

Equity Method Investments

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the fair value of these investments to their carrying values, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators, including the impact of COVID-19. If an impairment exists and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's fair value. No impairment of equity method investments was required for either 2019 or 2020.

Financial Assets

Equity investments, other than those accounted for under the equity method of accounting, are measured at fair value with changes in fair value recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable fair values are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required for either 2019 or 2020.

Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. AROs are included in "Other long-term liabilities" and accretion expense is included as part of "Depreciation and amortization". Any regulated accretion expense not yet approved by the regulator is recorded in "Property, plant and equipment" and included in the next depreciation study.

Some of the Company's transmission and distribution assets may have conditional ARO's which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value in the period in which an amount can be determined.

Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO costs of removal represent funds received from customers through depreciation rates to cover estimated future non-legally required cost of removal of property, plant and equipment upon retirement. The companies accrue for removal costs over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Stock-Based Compensation

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; a performance share unit ("PSU") plan; and a restricted share unit ("RSU") plan. The Company accounts for its plans in accordance with the fair value based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are initially measured at fair value and re-measured at fair value at each reporting date with the change in liability recognized in income.

Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCI or regulatory assets. The components of net periodic benefit cost other than the service cost component are included in "Other income (expense), net" on the Consolidated Statements of Income.

The COVID-19 pandemic could impact key actuarial assumptions used to account for employee post-retirement benefits 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.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2020, are described as follows:

Measurement of Credit Losses on Financial Instruments

The Company adopted Accounting Standard Update ("ASU") 2016-13, *Measurement of Credit Losses on Financial Instruments* effective January 1, 2020. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income. These include trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. The adoption of the standard resulted in a \$7 million decrease to retained earnings in the consolidated financial statements as of January 1, 2020.

Simplifying the Accounting for Income Taxes

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes*. The standard simplifies the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740 related to the approach for intraperiod tax allocation. It also simplifies aspects of accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard is applied on both a prospective and retrospective basis. The Company early adopted the standard effective January 1, 2020. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

The Company adopted ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* in Q4 2020. The standard provides options and exceptions for applying USGAAP to contract modifications and hedging relationships that reference the London Inter-Bank Offered Rate ("LIBOR") or any other reference rate that is expected to be discontinued. The guidance was effective as of the date of issuance and entities may elect to apply the guidance prospectively through December 31, 2022. The Company's transition from reference rates will not have a material impact on the consolidated financial statements. In November 2020, the Federal Reserve extended the phase-out of LIBOR until June 2023. The Company will continue to monitor the impact this may have on application of the standard.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

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

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

In August 2020, the FASB issued 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). 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. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2021. Early adoption is permitted, but no earlier than fiscal years beginning after December 15, 2020. The standard can be applied through either a modified retrospective method of transition or a fully retrospective method of transition. The Company early adopted the standard effective January 1, 2021 using the modified retrospective method. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

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 disclosure, 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 Consolidated Statements of Income.

Emera Maine's assets and liabilities were classified as held for sale at March 25, 2019. The Company continued recording depreciation on these assets through the transaction closing date, as the depreciation continued to be reflected in customer rates and was reflected in the carryover basis of the assets on completion of the sale. A total of \$53 million of depreciation and amortization was recorded on these assets from March 25, 2019, the date they were classified as held for sale, until the date of the sale. \$39 million of the \$53 million was recorded in 2019. Emera Maine's assets and liabilities were included in the Company's Other Electric Utilities segment.

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 year ended December 31, 2020							
Operating revenues from external customers (1)	\$ 2,473	\$ 1,494	\$ 474	\$ 1,051	\$ 14	\$ -	\$ 5,506
Inter-segment revenues (1)	7	-	-	7	15	(29)	-
Total operating revenues	2,480	1,494	474	1,058	29	(29)	5,506
Regulated fuel for generation and purchased power	574	659	194	-	-	(7)	1,420
Regulated cost of natural gas	-	-	-	293	-	-	293
OM&G	552	282	151	334	115	(15)	1,419
Depreciation and amortization	455	236	71	111	8	-	881
Income from equity investments	-	96	4	20	29	-	149
AFUDC - debt and equity	54	4	1	9	-	-	68
Interest expense, net	151	139	32	56	301	-	679
Internally allocated interest (2)	-	-	-	13	(13)	-	-
Gain on sale, net of transactions costs	-	-	-	-	585	-	585
Impairment charges	-	-	-	-	(25)	-	(25)
Income tax expense (recovery)	89	17	(8)	51	192	-	341
Net income (loss) attributable to common shareholders	501	221	35	162	19	-	938
Capital expenditures	1,361	338	148	749	4	-	2,600
As at December 31, 2020							
Total assets	16,889	6,752	1,365	6,067	1,234	(1,073) ⁽³⁾	31,234
Investments subject to significant influence	-	1,176	41	129	-	-	1,346
Goodwill	4,455	-	68	1,194	3	-	5,720

(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 year ended December 31, 2019							
Operating revenues from external customers (1)	\$ 2,596	\$ 1,429	\$ 744	\$ 1,097	\$ 245	\$ -	\$ 6,111
Inter-segment revenues (1)	11	1	-	22	37	(71)	-
Total operating revenues	2,607	1,430	744	1,119	282	(71)	6,111
Regulated fuel for generation and purchased power	772	573	286	-	-	(22)	1,609
Regulated cost of natural gas	-	-	-	350	-	-	350
OM&G	554	313	195	319	130	(47)	1,464
Depreciation and amortization	445	231	107	109	11	-	903
Income from equity investments	-	91	5	22	36	-	154
AFUDC - debt and equity	20	6	5	2	-	-	33
Interest expense, net	154	142	52	59	331	-	738
Internally allocated interest (2)	-	-	-	14	(14)	-	-
Impairment charges	-	-	34	-	-	-	34
Income tax expense (recovery)	79	(10)	11	48	(67)	-	61
Net income (loss) attributable to common shareholders	419	229	45	183	(213)	-	663
Capital expenditures	1,393	384	195	448	63	-	2,483
As at December 31, 2019							
Total assets	16,214	6,717	3,069	5,489	1,459	(1,106) ⁽³⁾	31,842
Investments subject to significant influence	-	1,133	41	138	-	-	1,312
Goodwill	4,544	-	70	1,218	3	-	5,835

(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.

Geographical Information

Revenues (1):

For the millions of Canadian dollars	Year ended December 31	
	2020	2019
Canada	\$ 1,569	\$ 1,497
United States	3,522	4,140
Barbados	263	320
The Bahamas	112	112
Dominica	40	42
	\$ 5,506	\$ 6,111

(1) Revenues are based on country of origin of the product or service sold.

Property Plant and Equipment:

As at millions of Canadian dollars	December 31 2020	December 31 2019
Canada	\$ 4,304	\$ 4,248
United States	14,353	13,095
Barbados	510	462
The Bahamas	289	282
Dominica	79	80
	\$ 19,535	\$ 18,167

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 year ended December 31, 2020							
Regulated							
Electric Revenue							
Residential	\$ 1,365	\$ 806	\$ 179	\$ -	\$ -	\$ -	\$ 2,350
Commercial	678	405	233	-	-	-	1,316
Industrial	178	224	32	-	-	-	434
Other electric and regulatory deferrals	242	31	8	-	-	-	281
Other (1)	17	28	22	1	-	(7)	61
Regulated electric revenue	2,480	1,494	474	1	-	(7)	4,442
Gas Revenue							
Residential	-	-	-	495	-	-	495
Commercial	-	-	-	275	-	-	275
Industrial	-	-	-	54	-	-	54
Finance income (2)(3)	-	-	-	61	-	-	61
Other	-	-	-	156	-	(7)	149
Regulated gas revenue	-	-	-	1,041	-	(7)	1,034
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	38	-	38
Energy sales (4)	-	-	-	-	16	(16)	-
Capacity	-	-	-	-	-	-	-
Other	-	-	-	16	21	-	37
Mark-to-market (3)	-	-	-	-	(46)	1	(45)
Non-regulated revenue	-	-	-	16	29	(15)	30
Total operating revenues	\$ 2,480	\$ 1,494	\$ 474	\$ 1,058	\$ 29	\$ (29)	\$ 5,506

(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 year ended December 31, 2019							
Regulated							
Electric Revenue							
Residential	\$ 1,387	\$ 746	\$ 276	\$ -	\$ -	\$ -	\$ 2,409
Commercial	745	400	339	-	-	-	1,484
Industrial	207	210	44	-	-	-	461
Other electric and regulatory deferrals	246	45	13	-	-	-	304
Other (1)	22	29	72	-	-	(12)	111
Regulated electric revenue	2,607	1,430	744	-	-	(12)	4,769
Gas Revenue							
Residential	-	-	-	502	-	-	502
Commercial	-	-	-	298	-	-	298
Industrial	-	-	-	50	-	-	50
Finance income (2)(3)	-	-	-	60	-	-	60
Other	-	-	-	193	-	(22)	171
Regulated gas revenue	-	-	-	1,103	-	(22)	1,081
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	31	-	31
Energy sales (4)	-	-	-	-	80	(12)	68
Capacity	-	-	-	-	38	-	38
Other	-	-	-	16	31	(25)	22
Mark-to-market (3)	-	-	-	-	102	-	102
Non-regulated revenue	-	-	-	16	282	(37)	261
Total operating revenues	\$ 2,607	\$ 1,430	\$ 744	\$ 1,119	\$ 282	\$ (71)	\$ 6,111

(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 December 31, 2020, the aggregate amount of the transaction price allocated to remaining performance obligations was \$464 million (2019 – \$347 million). This amount includes \$149 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

Regulatory assets represent prudently incurred costs that have been deferred because it is probable they will be recovered through future rates or tolls collected from customers. Management believes existing regulatory assets are probable for recovery either because the Company received specific approval from the applicable regulator, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

Regulatory Assets and Liabilities

As at millions of Canadian dollars	December 31 2020	December 31 2019
Regulatory assets		
Deferred income tax regulatory assets	\$ 887	\$ 862
Pension and post-retirement medical plan	394	380
Deferrals related to derivative instruments	65	81
Cost recovery clauses	49	13
Storm restoration regulatory asset	41	38
Environmental remediations	28	26
Stranded cost recovery	26	27
Demand side management ("DSM") deferral	15	19
Unamortized defeasance costs	13	19
Other	66	87
	\$ 1,584	\$ 1,552
Current	\$ 165	\$ 121
Long-term	1,419	1,431
Total regulatory assets	\$ 1,584	\$ 1,552
Regulatory liabilities		
Deferred income tax regulatory liabilities	933	985
Accumulated reserve - cost of removal	865	891
Storm reserve	62	62
Cost recovery clauses	31	53
Self-insurance fund (note 32)	28	29
Regulated fuel adjustment mechanism	21	115
Deferrals related to derivative instruments	15	42
Other	6	4
	\$ 1,961	\$ 2,181
Current	\$ 129	\$ 295
Long-term	1,832	1,886
Total regulatory liabilities	\$ 1,961	\$ 2,181

Deferred Income Tax Regulatory Assets and Liabilities

To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, a regulatory asset or liability is recognized as appropriate.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at Tampa Electric, PGS and NMGC. It is included in rate base and earns a rate of return as permitted by the FPSC and New Mexico Public Regulation Commission ("NMPRC") as applicable. It is amortized over the remaining service life of plan participants.

Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in fair value of derivatives that are documented as economic hedges or that do not qualify for NPNS exemption, as a regulatory asset or liability as approved by its regulator. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, inventory, operating, maintenance or general or property, plant and equipment, depending on the nature of the item being economically hedged.

Cost Recovery Clauses

These assets and liabilities are related to Tampa Electric, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in a subsequent period.

Storm Restoration Regulatory Asset

This asset represents storm restoration costs, primarily incurred by GBPC. GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are self-insured. On September 1, 2019, Hurricane Dorian struck Grand Bahama Island as a Category 5 hurricane, with sustained winds of approximately 285 kilometres per hour. The hurricane stalled over the island for several days, causing significant damage to, or destruction of, homes and businesses served by GBPC. GBPC's generation, transmission and distribution assets sustained damage, including the effect of flooding that resulted from storm surge and rain.

In January 2020, the Grand Bahama Port Authority ("GBPA") approved the recovery of \$15 million USD of costs related to the storm over a five-year period. The recovery was implemented through rates on January 1, 2021.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge over a five-year period. Additional details on the recovery are included under the Grand Bahama Power Company Limited section below. The balance of the regulatory asset as at December 31, 2020 is \$18 million USD.

Environmental Remediations

This asset is primarily related to PGS costs associated with environmental remediation at Manufactured Gas Plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

Stranded Cost Recovery

Due to the decommissioning of a GBPC steam turbine in 2012, the GBPA approved the recovery of a \$21 million USD stranded cost through electricity rates; it is included in rate base and is expected to be included in rates in future years.

DSM Deferral

The Nova Scotia Utility and Review Board (“UARB”) approved implementation of the 2015 DSM deferral set at \$35 million in 2015 and recoverable from customers over an 8-year period beginning in 2016.

The UARB directed EfficiencyOne, a franchisee appointed by the Province of Nova Scotia to provide NSPI with electricity efficiency and conservation activities under the *Public Utilities Act*, to review financing options through which EfficiencyOne would borrow the 2015 deferral amount from a commercial lender in order to repay NSPI the amount it expended on behalf of its customers in 2015. In December 2016, EfficiencyOne secured financing and \$31 million was advanced to NSPI to finance the 2015 DSM deferral. In February 2017, EfficiencyOne advanced an additional \$2 million to NSPI. As NSPI collects the associated amounts from customers over the remaining three years, it will repay the balance to EfficiencyOne. This has been set up as a liability in “Other long-term liabilities” with the current portion of the liability included in “Other current liabilities” on the Consolidated Balance Sheets.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust that provide the principal and interest streams to match the related defeased debt, which as at December 31, 2020, totalled \$582 million (2019 – \$740 million). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Accumulated Reserve – Cost of Removal (“COR”)

This regulatory liability represents the non-ARO COR reserve in Tampa Electric, PGS, NMGC and NSPI. AROs are costs for legally required removal of property, plant and equipment. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service.

Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric and PGS systems. As allowed by the FPSC, if the charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. Tampa Electric and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish the reserve. In September 2019, Tampa Electric incurred approximately \$8 million USD in storm restoration preparation costs for Hurricane Dorian. These costs were charged to the storm reserve regulatory liability.

Regulated Fuel Adjustment Mechanism

This regulated liability is the difference between actual fuel costs and amounts recovered from NSPI customers through electricity rates in a given year, and deferred to a fuel adjustment mechanism (“FAM”) regulatory asset or liability and recovered from or returned to customers in a subsequent year. As approved on December 6, 2019 as part of NSPI’s three-year Fuel Stability Plan, differences between actual fuel costs and fuel revenues recovered from customers for the years 2020 to 2022, will be recovered or returned to customers after 2022. The UARB’s decision to approve the Fuel Stability Plan directed that any annual non-fuel revenues above NSPI’s approved range of ROE are to be applied to the FAM.

Regulatory Environments

Florida Electric Utility

Tampa Electric is regulated by the FPSC. Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission ("FERC"). The FPSC sets rates at a level that allows utilities such as Tampa Electric to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

Tampa Electric's approved regulated return on equity ("ROE") range for 2020 and 2019 is 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.25 per cent is used for the calculation of the return on investments for clauses.

Fuel Recovery

Tampa Electric has a fuel recovery clause approved by the FPSC, allowing the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs including a return on capital invested. Differences between the prudently incurred fuel costs and the cost-recovery rates and amounts recovered from customers through electricity rates in a year are deferred to a regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Base rates

On February 1, 2021, Tampa Electric notified the FPSC of its intent to seek a base rate increase, reflecting incremental revenue requirements of approximately \$280 million USD to \$295 million USD, effective January 2022. Tampa Electric's proposed rates include recovery for the costs of the first phase of the Big Bend modernization project, 225 MW of utility-scale solar projects, the AMI investment, and accelerated recovery of the remaining net book value of retiring assets. Tampa Electric also intends to seek approval for Generation Base Rate Adjustments of \$130 million USD to recover the costs of the second phase of the Big Bend modernization project and additional utility-scale solar projects in subsequent years. These filing amounts are estimates until Tampa Electric completes and files its detailed case. Tampa Electric expects to file its detailed case on or after April 2, 2021, and a decision by the FPSC is expected by the end of 2021.

On April 9, 2019, Tampa Electric reached a settlement agreement with consumer parties regarding eligible storm costs as a result of Hurricane Irma in 2017, which was approved by the FPSC on May 21, 2019. As a result, Tampa Electric refunded \$12 million USD to customers in January 2020, resulting in minimal impact to the Consolidated Statements of Income.

On August 20, 2018, the FPSC approved a reduction in base rates of \$103 million USD annually beginning in 2019 as a result of lower tax expense due to 2018 US tax reform benefits.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2020, Tampa Electric has invested \$820 million USD in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). Tampa Electric expects to invest an additional \$30 million USD in these projects through 2021. AFUDC is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 600 MW or \$104 million USD annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates that were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A \$5 million USD true-up was returned to customers in 2020. The true-ups for SoBRA tranches 3 and 4 will be filed in 2021 and 2022, respectively.

Storm Protection Cost Recovery Clause and Settlement Agreement

On October 3, 2019, the FPSC issued a rule to implement a Storm Protection Plan ("SPP") Cost Recovery Clause. This new clause provides a process for Florida investor-owned utilities, including Tampa Electric, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Tampa Electric submitted its storm protection plan with the FPSC on April 10, 2020. On April 27, 2020, Tampa Electric submitted a settlement agreement with the FPSC which specified a \$15 million USD base rate reduction for SPP program costs previously recovered in base rates beginning January 1, 2021. On June 9, 2020, the FPSC approved this settlement agreement. On August 3, 2020, Tampa Electric submitted another settlement agreement to the FPSC for approval, including cost recovery of approximately \$39 million USD in proposed storm protection project costs for 2020 and 2021. This cost recovery includes the \$15 million USD of costs removed from base rates. This settlement agreement was approved on August 10, 2020 and Tampa Electric's cost recovery began in January 2021. The current approved plan will apply for the years 2020, 2021 and 2022, and Tampa Electric will file a new plan in 2022 to determine cost recovery in 2023, 2024, and 2025.

The June 9, 2020 settlement agreement approved by the FPSC disclosed above also included approval of Tampa Electric's petition to eliminate its \$16 million USD accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020.

Big Bend Modernization Project

Tampa Electric has invested approximately \$526 million USD through December 31, 2020 to modernize the Big Bend Power Station. The modernization project will repower Big Bend Unit 1 with natural gas combined-cycle technology and eliminate coal as this unit's fuel. On June 1, 2020, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant. At June 1, 2020 and December 31, 2020, the balance sheet included \$304 million (\$223 million USD) and \$255 million (\$200 million USD) respectively, in electric utility plant and \$123 million (\$90 million USD) and \$112 million (\$88 million USD) respectively, in accumulated depreciation related to Unit 1 components. In accordance with Tampa Electric's 2017 settlement agreement approved by the FPSC, Tampa Electric will continue to account for its existing investment in Unit 1 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study. In addition, Tampa Electric plans to retire Big Bend Unit 2 in 2021. In accordance with Tampa Electric's 2017 settlement agreement, Tampa Electric was not required to request an asset recovery schedule for retired assets until the next depreciation study. On December 30, 2020, Tampa Electric filed a depreciation and dismantlement study and request for capital recovery schedules with the FPSC.

Tampa Electric plans to retire Big Bend Unit 3 in 2023. Similar to the retirement plan for Unit 1 and Unit 2, Tampa Electric will continue to account for its existing investment in Unit 3 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study.

Canadian Electric Utilities

NSPI

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* ("Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI's approved regulated ROE range for 2020 and 2019 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent.

NSPI has a FAM, approved by UARB which enables it to seek recovery of its fuel costs from customers through regularly scheduled fuel rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

NSPI is currently operating under a three-year fuel stability plan which results in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. These rates include recovery of Maritime Link costs.

The Maritime Link is a \$1.6 billion transmission project including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018 and NSPI started paying the UARB approved interim assessment payments to NSPML at that time. The UARB approved 2020 interim cost assessment recovery payment to NSPML was \$145 million and as of December 31, 2020 \$135 million has been paid. The payments were subject to a holdback of \$10 million pending UARB agreement that a minimum of \$10 million in benefits from the Maritime Link are realized for NSPI customers. If the \$10 million in benefits is realized, the UARB will direct NSPI to pay the \$10 million to NSPML for that year. If not realized, then the UARB will direct NSPI to pay to NSPML only that portion that is realized and the balance will be refunded to customers through NSPI's FAM. For 2020, NSPI has recorded a \$4 million holdback payable to NSPML.

On December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment recovery from NSPI of Maritime Link costs of approximately \$172 million subject to a holdback of \$10 million on similar terms as previously approved by the UARB. It also includes a potential long-term deferral of up to \$23 million in depreciation expense dependent upon the timing of commencement of the Nova Scotia Block ("NS Block"). Refer to the NSPML section below for further detail.

As part of a three-year fuel stability plan, electricity rates have been set to include the \$145 million approved Maritime Link assessment for 2020 and estimate amounts of \$164 million and \$162 million for 2021 and 2022, respectively. Any difference between the amounts included in the Fuel Stability Plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

In response to the delayed timing of energy delivery from the Muskrat Falls project, which is being developed by Nalcor Energy, the approved Maritime Link interim assessment payments reflected a reduction in NSPML's assessment in each of 2018 and 2019, related to depreciation and amortization expenses. NSPI refunded the reduced 2018 NSPML assessment to customers in 2018 and 2019, by providing a credit to customers of \$17 million and \$35 million, respectively. The UARB's decision to approve NSPI's 2020-2022 fuel stability plan outlined the treatment of the reduced 2019 NSPML assessment of \$52 million plus interest. The majority of the reduced assessment was refunded to most customers through a reduction incorporated into their 2020 rates and the remaining customers received a one-time on bill credit in 2020. As at December 31, 2020, \$40 million plus interest has been refunded to customers, with the remaining \$12 million plus interest to be returned to customers subsequent to 2022.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On August 21, 2020, the FAM audit results for 2018 and 2019 were filed with the UARB. A hearing was held in January 2021 and a decision is expected in Q2 2021.

On March 13, 2020, the UARB's decision on the FAM audit findings and recommendations relating to fiscal 2016 and 2017 was released. The final recommendations did not include any disallowances.

NSPML

Equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

On December 16, 2020 the UARB approved NSPML's 2021 interim assessment for recovery of Maritime Link costs from NSPI of approximately \$172 million (2020 - \$145 million). This payment is subject to a holdback of \$10 million on similar terms as previously approved by the UARB. Recovery of \$115 million of operating and maintenance, debt financing and equity financing costs began on January 1, 2021. Recovery of \$57 million of depreciation and amortization will commence the sooner of the delivery of the NS Block or May 1, 2021. With cooperation of the Government of Canada, NSPML may also utilize up to \$23 million of cash in a debt related reserve account to reduce the recovery of costs from NSPI in 2021, depending upon when the NS Block commences. NSPML will file a final cost assessment with the UARB after the commencement of the NS Block which is anticipated to take place in 2021.

Other Electric Utilities

The Barbados Light & Power Company Limited

BLPC is regulated by the Fair Trading Commission ("FTC"), an independent regulator, under the Utilities Regulation (Procedural) Rules 2003. The Government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island 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. BLPC is currently negotiating the terms of the new licenses under the amended legislation.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide an appropriate return to investors. BLPC's approved regulated return on rate base was 10 per cent for 2020 and 2019.

On November 6, 2020, BLPC notified the FTC that it plans to file a general rate review application with the FTC in Q1 2021.

BLPC has a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The approved calculation of the fuel charge is adjusted monthly and reported to the regulator.

In December 2018, the Government of Barbados signed the *Income Tax Amendment Act* into law. This legislation, which was effective January 1, 2019, created a new corporate income tax rate schedule and eliminated certain tax credits. At the date of enactment, BLPC was required to remeasure its deferred income tax liability at the new lower corporate income tax rate, resulting in recognition of an income tax recovery of \$9.6 million USD of which \$6.9 million USD was deferred as a regulatory liability, all of which was recognized in earnings in Q1 2020.

Grand Bahama Power Company Limited

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. GBPC's approved regulated return on rate base was 8.34 per cent for 2020 (2019 - 8.5 per cent). In January 2021, the GBPA approved GBPC's regulated return on rate base of 8.37 per cent for 2021.

In December 2016, the GBPA approved that the all-in rate for electricity (fuel and base rates) would be held at 2016 levels over the five-year period from 2017 through 2021. Any over-recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory deferral, until such time as the deferral is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory deferral, the excess will be placed in a new storm reserve. If balances remain within the Hurricane Matthew deferral at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

Dominica Electricity Services Ltd

Domlec is regulated by the Independent Regulatory Commission, Dominica. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base was 15 per cent for 2020 and 2019.

Domlec has a fuel pass-through mechanism which provides opportunity to recover substantially all prudently incurred fuel costs in a timely manner.

Gas Utilities and Infrastructure

PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

PGS's approved ROE range for 2020 and 2019 was 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. An ROE of 10.75 per cent was used for the calculation of return on investments for clauses.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment clause. This clause is designed to recover actual costs incurred by PGS for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

The FPSC annually approves cost-recovery rates for conservation costs and Cast Iron/Bare Steel Pipe Replacement costs, including a return on capital invested incurred in developing and implementing energy conservation programs. The Cast Iron/Bare Steel Pipe Replacement clause is to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. The FPSC approved a replacement program of approximately 5 per cent, or 800 kilometres, of the PGS system at a cost of approximately \$80 million USD over a 10-year period beginning in 2013. In February 2017, the FPSC approved an amendment to the cast iron bare steel rider to include certain plastic materials and pipe deemed obsolete by Pipeline and Hazardous Materials Safety Administration, totaling approximately 880 kilometres. PGS estimates that all cast iron and bare steel pipe will be removed from its system by 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

PGS was permitted to initiate a general base rate proceeding during 2020, provided the new rates do not become effective before January 1, 2021. On June 8, 2020, PGS filed a petition for an increase in rates and service charges effective January 2021. On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase to base rates by \$58 million USD annually effective January 2021, which is a \$34 million USD increase in revenue and \$24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. This settlement agreement includes an allowed regulatory ROE range of 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint. It provides PGS the ability to reverse a total of \$34 million USD of accumulated depreciation through 2023 and sets new depreciation rates going into effect January 1, 2021 that are consistent with PGS's current overall average depreciation rate. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

NMGC

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to its cost of providing service, plus an appropriate return on invested capital.

NMGC's approved ROE for 2020 was 9.10 per cent and for 2019 ranged from 9.10-10.0 per cent. Beginning January 1, 2021, the approved ROE is 9.375 per cent, on an allowed equity capital structure of 52 per cent.

NMGC recovers gas supply costs through a purchased gas adjustment clause ("PGAC"). This clause recovers NMGC's actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC can adjust the charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. In December 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

NMGC filed a rate case in December 2019. NMGC reached an unopposed stipulated settlement of the case which was approved by the NMPRC in December 2020. The new rates reflect the recovery of capital investment in pipelines and related infrastructure and results in an increase in revenue of approximately \$5 million USD annually effective January 2021. The stipulated settlement agreement includes an allowed regulatory ROE 9.375 per cent on an allowed equity capital structure of 52 per cent. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2022, unless new federal tax rates are enacted, in which case NMGC can file for new rates to be effective earlier than January 1, 2023.

On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019 and allowed NMGC to retain tax reform benefits realized from January 1, 2018 to the effective date of the new rates. The new rates were phased in over two years, resulting in an annual revenue increase of approximately \$3 million USD. The deferred income tax regulatory liability of \$11 million (\$8 million USD) recorded at December 31, 2018 to reflect deferred tax benefits was recognized in revenue in Q2 2019. The NMPRC also approved the utility's weather adjustment mechanism. This clause is designed to lower the variability of weather impacts during the heating season period of October through April annually. The Weather Normalization Mechanism will make customer rates and Company revenue more predictable by minimizing the impact of warmer than usual or colder than usual weather. Revenue increases or decreases captured in the weather normalization mechanism from October to April will be adjusted annually in October of the following heating season.

Beginning in August 2019, the NMPRC approved a change in the treatment of net operating loss carryforwards. As a result of this change, a tax benefit of approximately \$7 million (\$5 million USD) was recognized in earnings in Q3 2019.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick to markets in the northeastern United States. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy Canada. The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract. The pipeline is considered a Group II pipeline regulated by the Canada Energy Regulator ("CER"). The CER Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the *CER Act* and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

8. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of Canadian dollars	Carrying Value As at December 31		Equity Income For the year ended December 31		Percentage of Ownership
	2020	2019	2020	2019	2020
LIL (1)	\$ 629	\$ 579	\$ 49	\$ 45	45.6
NSPML	547	554	47	46	100.0
M&NP (2)	129	138	20	22	12.9
Lucelec (2)	41	41	4	3	19.5
Bear Swamp (3)	-	-	29	35	50.0
Other Investments	-	-	-	3	
	\$ 1,346	\$ 1,312	\$ 149	\$ 154	

(1) Emera indirectly owns 100 per cent of the 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 \$118 million (2019 - \$137 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a \$12 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of Canadian dollars	2020	December 31 2019
Balance Sheets		
Current assets	\$ 57	\$ 69
Property, plant and equipment	1,629	1,671
Regulatory assets	210	177
Non-current assets	32	32
Total assets	\$ 1,928	\$ 1,949
Current liabilities	\$ 56	\$ 23
Long-term debt (1)	1,228	1,288
Non-current liabilities	97	84
Equity	547	554
Total liabilities and equity	\$ 1,928	\$ 1,949

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

9. OTHER INCOME (EXPENSES), NET

Other income (expenses), net consisted of the following:

For the millions of Canadian dollars	2020	Year ended December 31 2019
Allowance for equity funds used during construction	\$ 45	\$ 21
Gain on sale of Emera Maine, net of transaction costs (1)	585	-
TECO Guatemala Holdings award (2)	49	-
Other	29	(9)
	\$ 708	\$ 12

(1) Refer to note 4 for further detail related to the gain on sale of Emera Maine.

(2) Refer to note 27 for further detail related to the TECO Guatemala Holdings award.

10. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

millions of Canadian dollars	2020	2019
Income before provision for income taxes	\$ 1,325	\$ 771
Statutory income tax rate	29.5%	31%
Income taxes, at statutory income tax rate	391	239
Additional impact from the sale of Emera Maine	102	-
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	(48)	(66)
Foreign tax rate variance	(45)	(49)
Amortization of deferred income tax regulatory liabilities	(44)	(36)
Tax effect of equity earnings	(15)	(15)
Other	-	(12)
Income tax expense	\$ 341	\$ 61
Effective income tax rate	26%	8%

The increase in the effective income tax rate was primarily due to the sale of Emera Maine.

On March 10, 2020, Bill 243 of the Nova Scotia Financial Measures (2020) Act ("the Financial Measures Act") was enacted, which included a reduction in the Nova Scotia provincial corporate income tax rate from 16 per cent to 14 per cent. As a result, the Company's combined Canadian federal and provincial statutory income tax rate was reduced from 31 per cent to 29.5 per cent for 2020 and further reduced to 29 per cent for subsequent years.

As a result of this, the Company, in Q1 2020, was required to revalue certain of its Canadian deferred income tax assets and liabilities based on the new tax rates. The Company recorded a reduction of \$52 million to its net deferred income tax liabilities and an offsetting reduction to its net deferred income tax regulatory asset, as the benefit of lower net deferred income tax liabilities is expected to be returned to customers in future years. The Company also recognized a \$12 million income tax expense in Q1 2020 as a result of the revaluation of certain net deferred income tax assets.

On March 25, 2020, Bill C-13, the Canadian COVID-19 Emergency Response Act (“the COVID-19 Act”) was enacted, guaranteeing rapid implementation and administration of measures to protect Canadians’ health and safety, and stabilize the economy. In addition, the Government of Canada announced the opportunity for businesses to defer certain tax payments. There have been no material impacts to Emera’s financial position from the COVID-19 Act or the Government of Canada’s announcements.

On March 27, 2020, the United States Coronavirus Aid, Relief, and Economic Security (CARES) Act (“the CARES Act”) was signed into law. The CARES Act includes several business provisions including deferral of employer payroll taxes, an employee retention payroll tax credit, temporary changes to business interest expense disallowance rules, changes to net operating loss carryback and limitation rules and corporate alternative minimum tax (“AMT”) relief. Under the new AMT provisions, companies can accelerate the refund of AMT credit carryforwards. As a result, in Q1 2020, the Company reclassified \$77 million of AMT credit carryforwards from deferred income tax assets to receivables and other current assets. The Company received \$145 million of refundable AMT credit carryforwards in Q4 2020. The Company has not had any other material impacts from the CARES Act.

The following table reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars	2020	2019
Current income taxes		
Canada	\$ 18	\$ (19)
United States	(58)	(46)
Other	-	1
Deferred income taxes		
Canada	20	45
United States	426	137
Other	(9)	-
Investment tax credits		
United States	(10)	(9)
Operating loss carryforwards		
Canada	(46)	(48)
Income tax expense	\$ 341	\$ 61

The following table reflects the composition of income before provision for income taxes presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars	2020	2019
Canada	\$ 176	\$ 98
United States	1,142	682
Other	7	(9)
Income before provision for income taxes	\$ 1,325	\$ 771

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of Canadian dollars	2020	2019
Deferred income tax assets:		
Tax loss carryforwards	\$ 724	\$ 908
Tax credit carryforwards	319	311
Regulatory liabilities - cost of removal	184	195
Derivative instruments	108	145
Other	375	413
Total deferred income tax assets before valuation allowance	1,710	1,972
Valuation allowance	(202)	(193)
Total deferred income tax assets after valuation allowance	\$ 1,508	\$ 1,779
Deferred income tax (liabilities):		
Property, plant and equipment	\$ (2,450)	\$ (2,382)
Derivative instruments	(93)	(148)
Other	(385)	(348)
Total deferred income tax liabilities	\$ (2,928)	\$ (2,878)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	\$ 209	\$ 186
Long-term deferred income tax liabilities	(1,629)	(1,285)
Net deferred income tax liabilities	\$ (1,420)	\$ (1,099)

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for certain loss carryforwards and unrealized capital losses on investments. A valuation allowance of \$202 million has been recorded as at December 31, 2020 (2019 - \$193 million) related to the loss carryforwards and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, \$2.7 billion as at December 31, 2020 (2019 - \$1.9 billion) in cumulative temporary differences for which deferred taxes might otherwise be required, have not been recognized. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera's net operating loss ("NOL"), capital loss and tax credit carryforwards and their expiration periods as at December 31, 2020 consisted of the following:

millions of Canadian dollars	Gross Tax Carryforwards	Unrecognized Amounts	Net Tax Carryforwards	Expiration Period
Canada				
NOL	\$ 1,370	\$ (619)	\$ 751	2027 - 2040
Capital loss	61	(61)	-	Indefinite
United States				
Federal NOL	\$ 1,412	\$ -	\$ 1,412	2030 - 2040
State NOL	563	-	563	2032 - 2040
Tax credit	319	-	319	2025 - 2040
Other				
NOL	\$ 39	\$ (39)	\$ -	2021 - 2027

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	2020	2019
Balance, January 1	\$ 29	\$ 26
Increases due to tax positions related to current year	1	2
Increases due to tax positions related to a prior year	2	1
Decreases due to tax positions related to a prior year	(2)	-
Balance, December 31	\$ 30	\$ 29

The total amount of unrecognized tax benefits as at December 31, 2020 was \$30 million (2019 - \$29 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was \$6 million (2019 - \$5 million) with \$1 million of interest expense recognized in the Consolidated Statements of Income (2019 - \$1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next 12 months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is \$62 million, including interest. NSPI has prepaid \$23 million of the amount in dispute, as required by CRA.

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

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

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

Emera files a Canadian federal income tax return, which includes its Nova Scotia and New Brunswick provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, St. Lucia and Dominica income tax returns. As at December 31, 2020, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

11. COMMON STOCK

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

		2020		2019
	millions of	millions of	millions of	millions of
	shares	Canadian	shares	Canadian
		dollars		dollars
Issued and outstanding:				
Balance, December 31, 2019	242.48	\$ 6,216	234.12	\$ 5,816
Conversion of Convertible Debentures	-	-	0.03	1
Issuance of common stock (1)(2)	4.54	251	1.77	99
Issued under Purchase Plans at market rate	3.99	219	3.99	202
Discount on shares purchased under Dividend Reinvestment Plan	-	(4)	-	(7)
Options exercised under senior management share option plan	0.42	20	2.57	104
Employee Share Purchase Plan	-	3	-	1
Balance, December 31, 2020	251.43	\$ 6,705	242.48	\$ 6,216

(1) As at December 31, 2019, a total of 1,768,120 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of \$56.56 per share for gross proceeds of \$100 million (\$99 million net of issuance costs).

(2) For the year ended December 31, 2020, 4,544,025 common shares were issued under Emera's ATM program at an average price of \$56.04 per share for gross proceeds of \$255 million (\$251 million net of issuance costs).

On July 11, 2019, Emera established an ATM Program that allows the Company to issue up to \$600 million of common shares to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was established under a prospectus supplement to the Company's short-form base shelf prospectus which expires on July 14, 2021. As at December 31, 2020, an aggregate gross sales limit of \$245 million remains available for issuance under the ATM program.

On November 17, 2020, Emera filed an amendment to its July 11, 2019 prospectus supplement which established its ATM program. This amendment reflected changes in securities regulations related to ATM programs which were effective August 31, 2020. The amendment includes removal of the daily trading limit which previously provided that the number of shares sold could not exceed 25 per cent of the daily trading volume of the shares.

As at December 31, 2020, the following common shares were reserved for issuance: 3.5 million (2019 – 3.9 million) under the senior management stock option plan, 3.5 million (2019 – 0.9 million) under the employee common share purchase plan and 5.1 million (2019 – 8.8 million) under the dividend reinvestment plan ("DRIP").

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2020, Emera is in compliance with this requirement.

12. EARNINGS PER SHARE

Basic earnings per share ("EPS") is determined by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan, convertible debentures and shares issued under the dividend reinvestment plan.

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

For the millions of Canadian dollars (except per share amounts)	Year ended December 31	
	2020	2019
Numerator		
Net income attributable to common shareholders	\$ 937.6	\$ 662.8
Diluted numerator	937.6	662.8
Denominator		
Weighted average shares of common stock outstanding	246.5	238.5
Weighted average deferred share units outstanding	1.3	1.4
Weighted average shares of common stock outstanding – basic	247.8	239.9
Stock-based compensation	0.4	0.6
Weighted average shares of common stock outstanding – diluted	248.2	240.5
Earnings per common share		
Basic	\$ 3.78	\$ 2.76
Diluted	\$ 3.78	\$ 2.76

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income 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 on available-for- sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2020						
Balance, January 1, 2020	\$ 253	\$ 4	\$ (1)	\$ (1)	\$ (160)	\$ 95
Other comprehensive income (loss) before reclassifications	(201)	26	-	-	-	(175)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	2	-	(1)	1
Net current period other comprehensive income (loss)	(201)	26	2	-	(1)	(174)
Balance, December 31, 2020	\$ 52	\$ 30	\$ 1	\$ (1)	\$ (161)	\$ (79)
For the year ended December 31, 2019						
Balance, January 1, 2019 (1)	\$ 654	\$ (74)	\$ (7)	\$ (1)	\$ (234)	\$ 338
Other comprehensive income (loss) before reclassifications	(401)	78	3	-	-	(320)
Amounts reclassified from accumulated other comprehensive income loss	-	-	3	-	74	77
Net current period other comprehensive income (loss)	(401)	78	6	-	74	(243)
Balance, December 31, 2019	\$ 253	\$ 4	\$ (1)	\$ (1)	\$ (160)	\$ 95

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

For the	Year ended December 31	
millions of Canadian dollars	2020	2019
Affected line item in the Consolidated Financial Statements		
Losses on derivatives recognized as cash flow hedges		
Foreign exchange forwards	Operating revenue - regulated	\$ 2 \$ 3
Total before tax		2 3
Total net of tax		\$ 2 \$ 3
Net change in unrecognized pension and post-retirement benefit costs		
Actuarial losses (gains)	Other income, net	\$ 15 \$ 17
Past service costs (gains)	Other income, net	(1) (1)
Amounts reclassified into obligations	Pension and post-retirement benefits	(16) 39
Amounts reclassified into obligations	Regulatory assets	- 28
Total before tax		(2) 83
	Income tax recovery (expense)	1 (9)
Total net of tax		\$ (1) \$ 74
Total reclassifications out of AOCI, net of tax, for the period		\$ 1 \$ 77

14. INVENTORY

As at millions of Canadian dollars	December 31 2020	December 31 2019
Fuel	\$ 199	\$ 232
Materials	254	235
	\$ 453	\$ 467

15. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	December 31 2020	December 31 2019	December 31 2020	December 31 2019
<i>Cash flow hedges</i>				
Interest rate hedge	\$ 1	\$ -	\$ -	\$ -
Foreign exchange forwards	-	-	-	1
	1	-	-	1
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	1	8	6	39
Power purchases	10	23	34	36
Natural gas purchases and sales	4	2	2	5
Heavy fuel oil purchases	1	1	5	-
Foreign exchange forwards	-	2	17	6
	16	36	64	86
<i>HFT derivatives</i>				
Power swaps and physical contracts	13	19	13	22
Natural gas swaps, futures, forwards, physical contracts	139	151	346	381
	152	170	359	403
<i>Other derivatives</i>				
Equity derivatives	-	1	1	-
Foreign exchange forwards	15	-	-	-
	15	1	1	-
Total gross current derivatives	184	207	424	490
Impact of master netting agreements with intent to settle net or simultaneously	(86)	(120)	(86)	(120)
	98	87	338	370
Current	73	54	251	268
Long-term	25	33	87	102
Total derivatives	\$ 98	\$ 87	\$ 338	\$ 370

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 Consolidated Balance Sheets, are summarized in the following table:

As at millions of Canadian dollars	Derivative Assets		Derivative Liabilities	
	December 31 2020	December 31 2019	December 31 2020	December 31 2019
Regulatory deferral	\$ 2	\$ 8	\$ 2	\$ 8
HFT derivatives	84	112	84	112
Total impact of master netting agreements with intent to settle net or simultaneously	\$ 86	\$ 120	\$ 86	\$ 120

Cash Flow Hedges

As at December 31, 2020 the Company had a treasury lock in place to hedge the interest rate risk associated with the refinancing of long-term debt due in June 2021. During 2020 the Company also had foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline. The foreign exchange forwards designated as cash flow hedges settled in 2020.

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

For the millions of Canadian dollars	Year ended December 31			
	2020		2019	
	Foreign exchange forwards	Interest rate hedge	Foreign exchange forwards	
Realized gain (loss) in operating revenue – regulated	\$ (2)	\$ -	\$ (3)	
Total gains (losses) in net income	\$ (2)	\$ -	\$ (3)	

As at millions of Canadian dollars	December 31			
	2020		2019	
	Foreign exchange forwards	Interest rate hedge	Foreign exchange forwards	
Total unrealized gain (loss) in AOCI – effective portion, net of tax	\$ -	\$ 1	\$ (1)	

The Company expects \$1 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months, as the underlying hedged transactions settle.

As at December 31, 2020, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2021
U.S. Treasury lock (USD)	\$ 350

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	2020		Year ended December 31 2019	
	Commodity swaps and forwards	Foreign exchange forwards	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	\$ (36)	\$ (11)	\$ (89)	\$ (6)
Unrealized gain (loss) in regulatory liabilities	3	3	9	(8)
Realized gain (loss) in regulatory assets	2	-	-	-
Realized (gain) loss in regulatory liabilities	14	-	(2)	-
Realized (gain) loss in inventory (1)	8	(2)	(36)	(11)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	24	(3)	3	(8)
Total change derivative instruments	\$ 15	\$ (13)	\$ (115)	\$ (33)

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

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

Commodity Swaps and Forwards

As at December 31, 2020, 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)	5	7
Power (MWh)	2	2
Heavy fuel oil (bbls)	-	1
Coal (metric tonnes)	-	1

Foreign Exchange Swaps and Forwards

As at December 31, 2020, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated as regulated deferral that are expected to settle as outlined below:

	2021	2022-2023
Foreign exchange contracts (millions of US dollars)	\$ 160	\$ 135
Weighted average rate	1.3339	1.3266
% of USD requirements	78%	37%

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	Year ended December 31	
	2020	2019
Power swaps and physical contracts in non-regulated operating revenues	\$ (1)	\$ 1
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	205	281
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	(4)	(6)
	\$ 200	\$ 276

As at December 31, 2020, 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)	387	61	45	26	26
Natural gas sales (Mmbtu)	412	50	17	2	2
Power purchases (MWh)	2	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at December 31, 2020, 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 \$100 million USD and expire in 2021.

For the millions of Canadian dollars	Year ended December 31			
	2020		2019	
	Foreign Exchange Forwards	Equity Derivatives	Foreign Exchange Forwards	Equity Derivatives
Unrealized gain (loss) in operating, maintenance and general	\$ -	\$ (1)	\$ -	\$ 1
Unrealized gain (loss) in other income (expense), net	15	-	-	-
Realized gain (loss) in operating, maintenance and general	-	(3)	-	27
Realized gain (loss) in other income (expense)	(2)	-	-	-
Total gains (losses) in net income	\$ 13	\$ (4)	\$ -	\$ 28

Credit Risk

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

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

As at December 31, 2020, the maximum exposure the Company has to credit risk is \$805 million (2019 - \$860 million), which includes accounts receivable net of collateral/deposits and assets related to derivatives.

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 total cash deposits/collateral on hand as at December 31, 2020 was \$251 million (2019 - \$259 million), which mitigates the Company's maximum credit risk exposure. 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 ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2020, the Company had \$123 million (2019 - \$115 million) in financial assets, considered to be past due, which have been outstanding for an average 70 days. The fair value of these financial assets is \$101 million (2019 - \$106 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.

Concentration Risk

The Company's concentrations of risk consisted of the following:

As at	December 31, 2020		December 31, 2019	
	millions of Canadian dollars	% of total exposure	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	\$ 341	32%	\$ 344	31%
Commercial	143	14%	170	15%
Industrial	49	5%	66	6%
Other	96	9%	131	12%
	629	60%	711	64%
Trading group				
Credit rating of A- or above	54	5%	38	3%
Credit rating of BBB- to BBB+	41	4%	59	5%
Not rated	75	7%	95	9%
	170	16%	192	17%
Other accounts receivable	159	15%	184	16%
Classification as assets held for sale (1)	-	0%	(55)	-5%
	958	91%	1,032	92%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	60	6%	47	4%
Credit rating of BBB- to BBB+	13	1%	8	1%
Not rated	25	2%	32	3%
	98	9%	87	8%
	\$ 1,056	100%	\$ 1,119	100%

(1) Emera Maine's assets and liabilities were classified as held for sale at December 31, 2019. On March 24, 2020, Emera completed the sale of Emera Maine. Refer to note 4 for further detail.

Cash Collateral

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

As at	December 31	December 31
millions of Canadian dollars	2020	2019
Cash collateral provided to others	\$ 69	\$ 101
Cash collateral received from others	6	2

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 December 31, 2020, the total fair value of derivatives in a liability position, was \$338 million (December 31, 2019 – \$370 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.

16. 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 1) 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	December 31, 2020			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Cash flow hedges</i>				
Interest rate hedge	\$ 1	\$ -	\$ -	\$ 1
	1	-	-	1
<i>Regulatory deferral</i>				
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
<i>HFT derivatives</i>				
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
<i>Other derivatives</i>				
Foreign exchange forwards	-	15	-	15
	-	15	-	15
Total assets	16	68	14	98
Liabilities				
<i>Regulatory deferral</i>				
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
<i>HFT derivatives</i>				
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
<i>Other derivatives</i>				
Equity derivatives	1	-	-	1
	1	-	-	1
Total liabilities	42	38	258	338
Net assets (liabilities)	\$ (26)	\$ 30	\$ (244)	\$ (240)

As at	December 31, 2019			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Power purchases	\$ 23	\$ -	\$ -	\$ 23
Natural gas purchases and sales	-	2	-	2
Heavy fuel oil purchases	-	1	-	1
Foreign exchange forwards	-	2	-	2
	23	5	-	28
<i>HFT derivatives</i>				
Power swaps and physical contracts	1	3	1	5
Natural gas swaps, futures, forwards, physical contracts and related transportation	(7)	46	14	53
	(6)	49	15	58
<i>Other derivatives</i>				
Equity derivatives	1	-	-	1
	1	-	-	1
Total assets	18	54	15	87
Liabilities				
<i>Cash flow hedges</i>				
Foreign exchange forwards	-	1	-	1
	-	1	-	1
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	31	-	31
Power purchases	36	-	-	36
Natural gas purchased and sales	3	2	-	5
Foreign exchange forwards	-	6	-	6
	39	39	-	78
<i>HFT derivatives</i>				
Power swaps and physical contracts	5	2	-	7
Natural gas swaps, futures, forwards and physical contracts	2	33	249	284
	7	35	249	291
Total liabilities	46	75	249	370
Net assets (liabilities)	\$ (28)	\$ (21)	\$ (234)	\$ (283)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2020 was as follows:

millions of Canadian dollars	<i>HFT Derivatives</i>		
	Power	Natural gas	Total
Balance, January 1, 2020	\$ 1	\$ 14	\$ 15
Total realized and unrealized gains (losses) included in non-regulated operating revenues	3	(2)	1
Net transfers out of Level 3	(2)	-	(2)
Balance, December 31, 2020	\$ 2	\$ 12	\$ 14

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2020 was as follows:

millions of Canadian dollars	HFT Derivatives		
	Power	Natural gas	Total
Balance, January 1, 2020	\$ -	\$ 249	\$ 249
Total realized and unrealized gains included in non-regulated operating revenues	2	8	10
Net transfers out of Level 3	(1)	-	(1)
Balance, December 31, 2020	\$ 1	\$ 257	\$ 258

The Company evaluates observable inputs of market data on a quarterly basis to determine if transfers between levels is appropriate. For the year ended December 31, 2020, transfers out of Level 3 were a result of an increase in observable inputs.

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				December 31, 2020	
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Weighted Range average (1)	
Assets					
<i>HFT derivatives – Power swaps and physical contracts</i>	\$ 1	Modelled pricing	Third-party pricing	\$20.50 - \$62.45	\$31.14
			Probability of default	0.02% - 9.74%	2.52%
			Discount rate	0.01% - 0.73%	0.25%
	1	Modelled pricing	Third-party pricing	\$25.70 - \$36.05	\$29.53
			Probability of default	0.36% - 0.85%	0.60%
			Discount rate	0.06% - 0.41%	0.28%
<i>HFT derivatives – Natural gas swaps, futures, forwards and physical contracts</i>	18	Modelled pricing	Third-party pricing	\$1.66 - \$6.22	\$2.52
			Probability of default	0.02% - 2.52%	0.40%
			Discount rate	0.00% - 10.36%	0.75%
	(6)	Modelled pricing	Third-party pricing	\$1.82 - \$8.44	\$4.66
			Basis adjustment	\$0.00 - \$1.33	\$0.44
			Probability of default	0.02% - 12.58%	\$1.95
Discount rate	0.00% - 0.67%	0.13%			
Total assets	\$ 14				
Liabilities					
<i>HFT derivatives – Power swaps and physical contracts</i>	\$ 1	Modelled pricing	Third-party pricing	\$1.13 - \$62.45	\$36.90
			Own credit risk	0.02% - 6.85%	2.02%
			Discount rate	0.01% - 0.73%	0.34%
	1	Modelled pricing	Third-party pricing	\$37.25 - \$62.45	\$55.00
			Own credit risk	0.36% - 1.28%	0.83%
			Discount rate	0.01% - 0.40%	0.31%
<i>HFT derivatives – Natural gas swaps, futures, forwards and physical contracts</i>	226	Modelled pricing	Third-party pricing	\$1.44 - \$6.57	\$3.68
			Own credit risk	0.02% - 2.52%	0.10%
			Discount rate	0.00% - 8.79%	0.43%
	30	Modelled pricing	Third-party pricing	\$1.54 - \$8.44	\$4.69
			Basis adjustment	\$0.00 - \$1.33	\$0.87
			Own credit risk	0.03% - 12.58%	0.10%
Discount rate	0.00% - 0.67%	0.16%			
Total liabilities	\$ 258				
Net assets (liabilities)	\$ (244)				

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

As at	December 31, 2019				
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
<i>HFT derivatives – Power swaps and physical contracts</i>	\$ 1	Modelled pricing	Third-party pricing	\$21.40 - \$74.05	\$35.03
			Probability of default	0.01% - 1.14%	0.21%
			Discount rate	0.15% - 6.65%	2.78%
<i>HFT derivatives – Natural gas swaps, futures, forwards, and physical contracts</i>	9	Modelled pricing	Third-party pricing	\$1.63 - \$7.45	\$2.37
			Probability of default	0.01% - 2.31%	0.09%
			Discount rate	0.01% - 20.93%	1.55%
	5	Modelled pricing	Third-party pricing	\$1.33 - \$8.76	\$5.05
			Basis adjustment	\$0.00 - \$1.31	\$0.76
			Probability of default	0.01% - 3.33%	0.28%
			Discount rate	0.01% - 4.71%	0.91%
Total assets	\$ 15				
Liabilities					
<i>HFT derivatives – Natural gas swaps, futures, forwards and physical contracts</i>	228	Modelled pricing	Third-party pricing	\$1.54 - \$7.45	\$4.07
			Own credit risk	0.01% - 2.31%	0.12%
			Discount rate	0.01% - 18.63%	1.89%
	21	Modelled pricing	Third-party pricing	\$1.36 - \$9.75	\$5.45
			Basis adjustment	\$0.00 - \$1.31	\$0.91
			Own credit risk	0.01% - 3.33%	0.06%
			Discount rate	0.01% - 3.76%	0.81%
Total liabilities	\$ 249				
Net assets (liabilities)	\$ (234)				

Long-term debt is a financial liability not measured at fair value on the 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
December 31, 2020	\$ 13,721	\$ 16,487	\$ -	\$ 16,020	\$ 467	\$ 16,487
December 31, 2019	\$ 14,180	\$ 16,049	\$ -	\$ 15,598	\$ 451	\$ 16,049

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 gain of \$26 million was recorded in Other Comprehensive Income for the year ended December 31, 2020 (2019 – \$78 million).

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction 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 Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling \$139 million for the year ended December 31, 2020 (2019 - \$107 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 Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled \$18 million for the year ended December 31, 2020 (2019 - \$63 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2020 and at December 31, 2019.

18. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars	December 31 2020	December 31 2019
Customer accounts receivable – billed	\$ 570	\$ 603
Customer accounts receivable – unbilled	286	265
Allowance for credit losses	(22)	(9)
Capitalized transportation capacity (1)	200	272
Income tax receivable	11	118
Prepaid expenses	50	48
Other	138	189
	\$ 1,233	\$ 1,486

(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.

19. LEASES

Lessee

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 65 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

As at millions of Canadian dollars	Classification	December 31 2020	December 31 2019
Right-of-use asset	Other long-term assets	\$ 61	\$ 64
Lease liabilities			
Current	Other current liabilities	3	5
Long-term	Other long-term liabilities	60	61
Total lease liabilities		\$ 63	\$ 66

The Company has recorded lease expense of \$160 million for the year ended December 31, 2020 (2019 – \$172 million), of which \$149 million (2019 – \$156 million) relates to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Minimum lease payments	\$ 6	\$ 6	\$ 6	\$ 5	\$ 4	\$ 112	\$ 139
Less imputed interest	-	-	-	-	-	-	(76)
Total	\$ 6	\$ 6	\$ 6	\$ 5	\$ 4	\$ 112	\$ 63

Additional information related to Emera's leases is as follows:

For the	Year ended December	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of Canadian dollars)	\$ 7	\$ 7
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of Canadian dollars)	\$ 7	\$ 16
Weighted average remaining lease term (years)	43	39
Weighted average discount rate- operating leases	3.96%	4.07%

Lessor

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

Direct finance and sales-type lease unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Operating revenues – regulated gas" and "Other income (expense), net" on the Consolidated Statements of Income.

The Company manages its risk associated with the residual value of the Brunswick Pipeline lease through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets at any time after 2021 by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

Net investment in direct finance and sales-type leases consist of the following:

As at	December 31	December 31
millions of Canadian dollars	2020	2019
Total minimum lease payment to be received	1,018	\$ 1,066
Less: amounts representing estimated executory costs	(179)	(189)
Minimum lease payments receivable	839	\$ 877
Estimated residual value of leased property (unguaranteed)	183	183
Less: unearned finance lease income	(487)	(532)
Net investment in direct finance and sales-type leases	535	\$ 528
Principal due within one year (included in "Receivables and other current assets")	18	17
Net investment in sales-type leases - long-term (included in "Other long-term assets")	42	38
Net Investment in direct finance leases - long-term	475	\$ 473

As at December 31, 2020, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Minimum lease payments to be received	\$ 78	\$ 77	\$ 76	\$ 77	\$ 79	\$ 631	\$ 1,018
Less: executory costs							(179)
Minimum lease payments receivable	\$ 78	\$ 77	\$ 76	\$ 77	\$ 79	\$ 631	\$ 839

20. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at millions of Canadian dollars	Estimated useful life	December 31 2020	December 31 2019
Generation	3 to 131	\$ 11,474	\$ 11,181
Transmission	11 to 80	2,414	2,318
Distribution	4 to 80	5,997	5,820
Gas transmission and distribution	7 to 85	3,879	3,568
General plant and other (1)	2 to 60	2,127	2,006
Total cost		25,891	24,893
Less: Accumulated depreciation (1)		(8,714)	(8,317)
		17,177	16,576
Construction work in progress (1)		2,358	1,591
Net book value		\$ 19,535	\$ 18,167

(1) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2020, SeaCoast's share of plant in service was \$34 million, accumulated depreciation of nil and construction work in progress of nil. At December 31, 2019, SeaCoast's share of construction work in progress was \$8 million. SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest was a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in OM&G in the Consolidated Statements of Income.

21. 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. On March 24, 2020, Emera sold Emera Maine, refer to note 4 for further detail. As at December 31, 2019, Emera Maine's assets and liabilities, including balances related to benefit plans, were classified as held for sale.

Emera's net periodic benefit cost included the following:

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans were as follows:

For the millions of Canadian dollars	2020		Year ended December 31 2019	
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	\$ 2,822	\$ 353	\$ 2,650	\$ 350
Service cost	46	5	47	4
Plan participant contributions	7	5	8	5
Interest cost	84	10	102	14
Benefits paid	(135)	(27)	(130)	(23)
Actuarial losses	189	52	231	19
Settlements and curtailments	(229)	(52)	(20)	-
Foreign currency translation adjustment	(25)	(7)	(66)	(16)
Balance, December 31	2,759	339	2,822	353
Change in plan assets				
Balance, January 1	2,593	56	2,300	49
Employer contributions	41	21	52	19
Plan participant contributions	7	5	8	5
Benefits paid	(135)	(27)	(130)	(23)
Actual return on assets, net of expenses	310	5	424	7
Settlements and curtailments	(191)	(7)	(7)	-
Foreign currency translation adjustment	(20)	(1)	(54)	(1)
Balance, December 31	2,605	52	2,593	56
Funded status, end of year	\$ (154)	\$ (287)	\$ (229)	\$ (297)

The actuarial losses recognized in the period are primarily due to losses associated with changes in the discount rate and losses related to changes in member experience, such as terminations, retirements, and deaths. This was partially offset by gains associated with strong asset performance and changes in inflation and compensation-related assumptions.

Plans with PBO/APBO in Excess of Plan Assets

The aggregate financial position for all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeds the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	2020		2019	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	\$ 2,736	\$ 308	\$ 2,797	\$ 323
Fair value of plan assets	2,568	-	2,557	7
Funded status	\$ (168)	\$ (308)	\$ (240)	\$ (316)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets

The ABO for the defined benefit pension plans was \$2,639 million as at December 31, 2020 (2019 – \$2,687 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	2020	2019
	Defined benefit pension plans	Defined benefit pension plans
ABO	\$ 1,519	\$ 2,665
Fair value of plan assets	1,419	2,557
Funded status	\$ (100)	\$ (108)

Balance Sheet

The amounts recognized in the Consolidated Balance Sheets consisted of the following:

As at millions of Canadian dollars	December 31 2020		December 31 2019	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	\$ (4)	\$ (19)	\$ (4)	\$ (18)
Long-term liabilities	(163)	(290)	(206)	(254)
Long-term liabilities associated with assets held for sale (1)	-	-	(30)	(44)
Other long-term assets	13	20	11	19
Amount included in deferred income tax	(4)	(1)	(7)	1
AOCI and regulatory assets, net of tax	443	107	524	72
Net amount recognized	\$ 285	\$ (183)	\$ 288	\$ (224)

(1) On March 24, 2020, Emera sold Emera Maine, refer to note 4 for further details. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale.

Amounts Recognized in AOCI and Regulatory Assets

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2020	\$ 358	\$ 160	\$ (1)
Amortized in current period	(25)	(15)	1
Current year addition to AOCI or regulatory assets	(12)	14	-
Change in current year related to sale of Emera Maine	(39)	-	-
Change in foreign exchange rate	(3)	1	-
Balance, December 31, 2020	\$ 279	\$ 160	\$ -
Non-pension benefits plans			
Balance, January 1, 2020	\$ 78	\$ (5)	\$ -
Amortized in current period	-	-	-
Current year addition to AOCI or regulatory assets	48	2	-
Change in current year related to sale of Emera Maine	(13)	-	-
Change in foreign exchange rate	(3)	(1)	-
Balance, December 31, 2020	\$ 110	\$ (4)	\$ -

	2020		2019	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	\$ 160	\$ (4)	\$ 160	\$ (5)
Past service (gains) costs	-	-	(1)	-
Regulatory assets	279	110	358	78
Total AOCI and regulatory assets before deferred income taxes	439	106	517	73
Amount included in deferred income tax assets	4	1	7	(1)
Net amount in AOCI and regulatory assets	\$ 443	\$ 107	\$ 524	\$ 72

Benefit Cost Components

Emera's net periodic benefit cost included the following:

As at millions of Canadian dollars	2020		Year ended December 31 2019	
	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Service cost	\$ 46	\$ 5	\$ 47	\$ 4
Interest cost	84	10	102	14
Expected return on plan assets	(141)	(1)	(147)	(2)
Current year amortization of:				
Actuarial losses (gains)	15	-	16	-
Past service costs (gains)	(1)	-	(1)	-
Regulatory assets (liability)	25	-	20	(5)
Settlement, curtailments	-	-	1	-
Total	\$ 28	\$ 14	\$ 38	\$ 11

The expected return on plan assets is determined based on the market-related value of plan assets of \$2,476 million as at January 1, 2020 (2019 – \$2,401 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad range of investment and non-investment grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset Class	Target Range at Market		
Short-term securities	0%	to	5%
Fixed income	35%	to	50%
Equities:			
Canadian	12%	to	22%
Non-Canadian	30%	to	55%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Fixed income	30%	to	50%
Equities	50%	to	70%

Pension Plan assets are overseen by the respective Management Pension Committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

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

millions of Canadian dollars	NAV		Level 1		Level 2		Total	Percentage	
	December 31, 2020								
Cash and cash equivalents	\$	-	\$	68	\$	-	\$	68	3%
Net in-transits		-		(99)		-		(99)	(4)%
Equity Securities:									
Canadian equity		-		154		-		154	6%
US equity		-		380		-		380	15%
Other equity		-		243		-		243	9%
Fixed income securities:									
Government		-		-		119		119	5%
Corporate		-		-		141		141	5%
Other		-		10		3		13	-%
Mutual funds		-		88		-		88	3%
Other		-		(3)		(4)		(7)	-%
Open-ended investments measured at NAV (1)		801		-		-		801	31%
Common collective trusts measured at NAV (2)		704		-		-		704	27%
Total	\$	1,505	\$	841	\$	259	\$	2,605	100%

						December 31, 2019			
Cash and cash equivalents	\$	-	\$	44	\$	-	\$	44	2%
Net in-transits		-		(48)		-		(48)	(2)%
Equity securities:									
Canadian equity		-		210		-		210	8%
US equity		-		388		-		388	15%
Other equity		-		176		-		176	7%
Fixed Income securities:									
Government		-		-		93		93	3%
Corporate		-		-		126		126	5%
Other		-		5		9		14	-
Mutual funds		-		199		-		199	8%
Other		-		(5)		1		(4)	-%
Open-ended investments measured at NAV (1)		860		-		-		860	33%
Common collective trusts measured at NAV (2)		535		-		-		535	21%
Total	\$	1,395	\$	969	\$	229	\$	2,593	100%

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds.

NAV's are calculated daily and the funds honor subscription and redemption activity regularly.

(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

Refer to note 16 for more information on the fair value hierarchy and inputs used to measure fair value.

Post-Retirement Benefit Plans

There are no assets set aside to pay for most of the Company's post-retirement benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The primary exceptions to this is the NMGC Retiree Medical Plan, which is fully funded. Prior to its sale on March 24, 2020, the Emera Maine post-retirement benefit plans were partially funded.

Investments in Emera

As at December 31, 2020 and 2019, the assets related to the pension funds and post-retirement benefit plans do not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2021	\$ 41	\$ 19
Expected benefit payments		
2021	140	21
2022	154	22
2023	154	22
2024	162	22
2025	170	22
2026 – 2030	914	105

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2020		2019	
(weighted average assumptions)	Defined benefit pension plans	Non-pension benefit plans	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate - past service	2.49 %	2.48 %	3.17 %	3.27 %
Discount rate - future service	2.64 %	2.51 %	3.21 %	3.28 %
Rate of compensation increase	2.89 %	3.04 %	3.32 %	3.70 %
Health care trend - initial (next year)	-	5.64 %	-	6.15 %
- ultimate	-	4.35 %	-	4.38 %
- year ultimate reached		2038		2038
Benefit cost for year ended December 31:				
Discount rate - past service	3.17 %	3.28 %	4.05 %	4.30 %
Discount rate - future service	3.21 %	3.28 %	4.05 %	4.30 %
Expected long-term return on plan assets	6.29 %	3.25 %	6.50 %	2.81 %
Rate of compensation increase	3.34 %	3.70 %	3.30 %	3.67 %
Health care trend - initial (current year)	-	5.91 %	-	6.39 %
- ultimate	-	4.37 %	-	4.45 %
- year ultimate reached		2038		2035

Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2020 was \$45 million (2019 – \$34 million).

22. GOODWILL

The change in goodwill for the year ended December 31 is due to the following:

millions of Canadian dollars	2020	2019
Balance, January 1	\$ 5,835	\$ 6,313
Additions	-	3
GBPC impairment charge	-	(30)
Classified as assets held for sale ⁽¹⁾	-	(148)
Change in foreign exchange rate	(115)	(303)
Balance, December 31	\$ 5,720	\$ 5,835

(1) On March 25, 2019, Emera announced the sale of Emera Maine. Emera Maine's assets and liabilities were classified as held for sale. Refer to note 4 for further detail.

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2020, primarily relates to TECO Energy and GBPC. Emera's reporting units with goodwill are Tampa Electric, PGS, NMGC, and GBPC.

In 2020, Emera performed a qualitative impairment assessment for Tampa Electric, PGS and NMGC, concluding that the fair value of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessment were performed and no impairment charges were recognized.

Goodwill on Emera's Consolidated Balance Sheets at December 31, 2020, included \$68 million (2019 - \$70 million) related to GBPC. In 2019 Emera recognized an impairment charge of \$30 million based on the excess of GBPC's carrying amount over its fair value. The 2019 impairment charge is included in "Impairment charges" in the Consolidated Statements of Income. In 2020, due to the limited excess of fair value over carrying value as a result of the 2019 impairment charge, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment using a discounted cash flow analysis. This assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions used could result in a future impairment.

23. 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. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

millions of Canadian dollars	2020	Weighted average interest rate	2019	Weighted average interest rate
Tampa Electric Company ("TEC")				
Advances on accounts receivable and revolving credit facilities	\$ 987	0.89 %	\$ 452	2.56 %
Emera				
Non-revolving term facility	400	0.94 %	399	2.69 %
Bank indebtedness	-	- %	6	- %
TECO Finance				
Advances on revolving credit and term facilities	205	1.46 %	656	2.39 %
NMGC				
Advances on revolving credit facilities	21	1.22 %	8	2.70 %
GBPC				
Advances on revolving credit facilities	11	5.25 %	10	5.25 %
NSPI				
Bank indebtedness	1	- %	6	- %
Short-term debt	\$ 1,625		\$ 1,537	

The Company's total short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2020	2019
Tampa Electric Company - revolving credit facility	2023	\$ 1,019	\$ 520
TECO Energy/TECO Finance - revolving credit facility	2023	509	520
Emera - non-revolving term facility	2021	400	400
TEC - term loan	2021	382	-
TEC - accounts receivable revolving credit facility	2021	191	195
NMGC - revolving credit facility	2023	159	162
GBPC - revolving credit facility	on demand	17	17
TECO Energy/TECO Finance - term credit facility		-	649
Total		2,677	2,463
Less:			
Advances under revolving credit and term facilities		1,624	1,525
Letters of credit issued within the credit facilities		4	3
Total advances under available facilities		1,628	1,528
Available capacity under existing agreements		\$ 1,049	\$ 935

The weighted average interest rate on outstanding short-term debt at December 31, 2020 was 1.01 per cent (2019 – 2.54 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

On February 6, 2020, TEC entered into a \$300 million USD non-revolving credit agreement with a maturity date of February 4, 2021. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at the London interbank deposit rate ("LIBOR"), prime rate or the federal funds rate, plus a margin. On January 29, 2021, TEC extended the maturity date of the agreement to April 29, 2021 with no other changes in terms.

On December 18, 2020, TEC amended and restated its bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023 and increased the amount of the commitment by the lenders to \$800 million USD from \$400 million USD. The credit facility bears interest based on either the LIBOR, the Wells Fargo Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a \$80 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Gas Utilities and Infrastructure

On December 18, 2020, NMGC amended and restated its \$125 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a \$30 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Other

On February 28, 2020, TECO Finance extended the maturity date of its \$500 million USD credit facility from March 5, 2020 to July 3, 2020. There were no other significant changes in commercial terms from the prior agreement. Using funds from the sale of Emera Maine, on April 3, 2020, TECO Finance repaid \$200 million USD of the term loan and the remaining \$300 million USD was repaid on June 30, 2020.

On December 1, 2020, Emera extended the maturity date of its \$400 million non-revolving term loan from December 15, 2020 to December 16, 2021. There were no other significant changes in commercial terms from the prior agreement.

On December 18, 2020, TECO Finance amended and restated its \$400 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The facility now includes a \$50 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

24. OTHER CURRENT LIABILITIES

As at millions of Canadian dollars	December 31 2020	December 31 2019
Accrued charges	\$ 141	\$ 147
Accrued interest on long-term debt	71	77
Pension and post-retirement liabilities (note 21)	23	22
Sales and other taxes payable	6	13
Income tax payable	1	1
Other	98	73
	\$ 340	\$ 333

25. LONG-TERM DEBT

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Weighted average interest rate (1)		Maturity		
	2020	2019		2020	2019
Emera					
Bankers acceptances, LIBOR loans	Variable	Variable	2024	\$ 263	\$ 437
Unsecured fixed rate notes	2.90%	2.90%	2023	500	500
Fixed to floating subordinated notes (USD)	6.75%	6.75%	2076	1,528	1,559
				\$ 2,291	\$ 2,496
Emera Finance					
Unsecured senior notes (USD)	3.86%	3.86%	2021 - 2046	\$ 3,501	\$ 3,572
TECO Finance					
Fixed rate notes and bonds (USD)	-	5.15%	-	\$ -	390
Tampa Electric (2)					
Fixed rate notes and bonds (USD)	4.53%	4.53%	2021 - 2050	\$ 3,268	\$ 3,334
PGS					
Fixed rate notes and bonds (USD)	4.58%	4.58%	2021 - 2050	\$ 429	\$ 437
NMGC					
Fixed rate notes and bonds (USD)	4.30%	4.30%	2021 - 2049	\$ 465	\$ 474
NMGI					
Fixed rate notes and bonds (USD)	3.64%	3.64%	2024	\$ 191	\$ 195
NSPI					
Discount notes	Variable	Variable	2024	\$ 291	\$ 308
Medium term fixed rate notes	5.14%	5.37%	2025 - 2097	2,665	2,365
				\$ 2,956	\$ 2,673
Emera Maine					
LIBOR loans and demand loans		Variable		\$ -	\$ 11
Secured fixed rate mortgage bonds (USD)	-	9.74%	-	-	65
Unsecured senior fixed rate notes (USD)	-	4.15%	-	-	442
				\$ -	\$ 518
EBP					
Senior secured credit facility	Variable	Variable	2023	\$ 249	\$ 248
ECI					
Secured senior notes (USD)	Variable	Variable	2021 - 2031	\$ 106	\$ 130
Amortizing fixed rate notes (USD)	3.92%	3.89%	2021 - 2022	100	122
Non-revolving term facility, floating rate	Variable	-	2025	28	-
Non-revolving term facility, fixed rate	2.60%	-	2025	68	-
Secured fixed rate senior notes (3)	4.39%	4.84%	2022 - 2035	174	218
				\$ 476	\$ 470
Adjustments					
Fair market value adjustment - TECO Energy acquisition (4)				\$ 5	\$ 8
Debt issuance costs				(110)	(119)
Classification as liabilities held for sale (5)				-	(516)
Amount due within one year				(1,382)	(501)
				\$ (1,487)	\$ (1,128)
Long-Term Debt				\$ 12,339	\$ 13,679

(1) Weighted average interest rate of fixed rate long-term debt.

(2) A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

(3) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).

(4) On acquisition of TECO Energy, Emera recorded a fair market value adjustment on the unregulated long-term debt acquired. The fair market value adjustment is amortized over the remaining term of the debt.

(5) On March 24, 2020 Emera sold Emera Maine. Refer to note 4 for further detail. As at December 31, 2019, Emera Maine's assets and liabilities are classified as held for sale.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2020	2019
Emera – revolving credit facility (1)	June 2024	\$ 900	\$ 900
NSPI - revolving credit facility (1)	October 2024	600	600
ECI – revolving credit facilities	2021-2023	28	25
Emera Maine – revolving credit facility		-	104
Total		1,528	1,629
Less:			
Borrowings under credit facilities		569	771
Letters of credit issued inside credit facilities		31	65
Use of available facilities		600	836
Available capacity under existing agreements		\$ 928	\$ 793

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to \$50 million.

Debt Covenants

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenants are listed below:

	Financial Covenant	Requirement	As at December 31, 2020
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.56 : 1

Recent Significant Financing Activity by Segment

Canadian Electric Utilities

On April 24, 2020, NSPI completed a \$300 million 30-year unsecured notes issuance. The notes bear interest at a rate of 3.31 per cent and have a maturity date of April 25, 2050.

Other Electric Utilities

On May 20, 2020, GBPC entered into a \$22 million USD non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 90-day LIBOR plus a margin. On May 22, 2020, proceeds from this loan were used to repay \$22 million USD senior notes upon maturity.

On May 20, 2020, GBPC entered into a \$15 million BSD (\$15 million USD) non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 4.00 per cent.

At December 31, 2020, BLPC had drawn \$77 million BBD (\$38 million USD) against a \$110 million BBD (\$55 million USD) non-revolving term loan. The loan bears interest at a rate of 2.05 per cent and has a 5-year term.

Gas Utilities and Infrastructure

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 and for general corporate purposes. These notes were classified as long-term debt at December 31, 2020.

Other

On March 13, 2020, TECO Finance repaid a \$300 million USD note upon maturity. The note was repaid using existing credit facilities.

Long-Term Debt Maturities

As at December 31, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Emera	\$ -	\$ -	\$ 500	\$ 263	\$ -	\$ 1,528	\$ 2,291
Emera US Finance LP	955	-	-	-	-	2,546	3,501
Tampa Electric	295	286	-	-	-	2,687	3,268
PGS	59	33	-	-	-	337	429
NMGC	-	-	-	-	-	465	465
NMGI	-	-	-	191	-	-	191
NSPI	-	-	-	291	125	2,540	2,956
EBP	-	-	249	-	-	-	249
ECI	73	88	60	75	101	79	476
Total	\$ 1,382	\$ 407	\$ 809	\$ 820	\$ 226	\$ 10,182	\$ 13,826

26. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars	2020	2019
Balance, January 1	\$ 185	\$ 205
Additions	10	-
Liabilities settled (1)	(25)	(25)
Accretion included in depreciation expense	9	7
Accretion deferred to regulatory asset (included in property, plant and equipment)	(3)	-
Other	1	3
Change in foreign exchange rate	1	(5)
Balance, December 31	\$ 178	\$ 185

(1) Tampa Electric produces ash and other by-products, collectively known as CCR's, at its Big Bend and Polk power stations. The decreases in ARO in 2020 and 2019 are due to the closure of CCR management facilities.

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2020, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, 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
Purchased power (1)	\$ 231	\$ 218	\$ 216	\$ 218	\$ 224	\$ 2,242	\$ 3,349
Transportation (2)	518	393	339	306	282	2,704	4,542
Capital projects	394	98	76	-	-	-	568
Fuel, gas supply and storage	494	91	6	1	-	-	592
Long-term service agreements (3)	43	41	36	33	34	92	279
Equity investment commitments (4)	-	240	-	-	-	-	240
Leases and other (5)	16	17	16	15	8	118	190
Demand side management	40	45	-	-	-	-	85
	\$ 1,736	\$ 1,143	\$ 689	\$ 573	\$ 548	\$ 5,156	\$ 9,845

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.

(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of \$149 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(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 Labrador Island Link Limited Partnership.

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

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing project commissioning in 2021.

NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls, which is anticipated to take place in 2021. On December 16, 2020, the UARB approved NSPML's 2021 interim assessment for recovery from NSPI of Maritime Link costs of approximately \$172 million subject to a holdback of \$10 million with similar terms as previously approved by the UARB and potential long-term deferral of up to \$23 million in depreciation expense dependent upon the timing of commencement of the NS Block.

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 the \$145 million approved for 2020 and amounts of \$164 million and \$162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved the 2021 interim cost assessment of approximately \$172 million. 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 dependent on regulatory filings with the UARB.

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 Energy, if requested, to enable them to transmit energy which is not otherwise used in Newfoundland or Nova Scotia. This energy could be transmitted from Nova Scotia to New England energy markets beginning at first commercial power of the Muskrat Falls hydroelectric generating facility and related transmission assets when Nalcor commences delivery of the NS Block, 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 that resided in Guatemala. In 2013, the ICSID tribunal hearing an arbitration claim of TGH against the Republic of Guatemala ("Guatemala") under the Dominican Republic Central America – United States Free Trade Agreement, issued an award. 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. The ICSID Tribunal unanimously found in favour of TGH and awarded damages to TGH of approximately \$21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus 2 per cent. Subsequent proceedings resulted in Guatemala awards of additional interest and certain costs to TGH (in aggregate, the "First Award"). In November 2020, Guatemala withdrew its appeal in U.S. courts against the enforcement of the First Award and made a payment of approximately \$38 million USD in full and final satisfaction of the First Award. This amount was recognized in "Other Income, net" on the Consolidated Statements of Income.

On September 23, 2016, TGH had filed a separate request for resubmission to arbitration seeking damages in addition to those awarded in the First Award. On May 13, 2020, a second 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. Guatemala now has until February 16, 2021 to seek annulment of the Second Award before ICSID. To date, the total of the Second Award, with interest, is approximately \$59 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 December 31, 2020, 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 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.

Emera Maine

On March 24, 2020, the Company completed the sale of Emera Maine. Emera has no remaining obligations with respect to the legal proceedings previously disclosed in note 26 of Emera's 2019 annual audited consolidated financial statements. No new or additional reserves were made in 2020 with respect to any of the four complaints filed with the FERC.

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 15 and note 16.

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 expenditures, 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 adjusted 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 expenditures, 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, increase 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 expenditures, 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 has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2020:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of \$45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which is expected to terminate on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of \$27 million USD.

Emera Inc. has issued a guarantee of up to \$35 million USD relating to outstanding notes of GBPC. The guarantee for the notes will expire in May 2023.

In 2020, NSPI issued guarantees in the amount of \$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.

The Company has standby letters of credit and surety bonds in the amount of \$55 million USD (December 31, 2019 - \$82 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2021. The amount committed as at December 31, 2020 was \$63 million (December 31, 2019 - \$52 million).

Collaborative Arrangements

For the years ended December 31, 2020 and 2019, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in OM&G expenses. In 2020, NSPI recognized \$19 million net expense (2019 - \$19 million) in "Regulated fuel for generation and purchased power" and \$3 million (2019 - \$3 million) in OM&G.

28. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

		December 31, 2020			December 31, 2019	
	Annual Dividend Per Share	Redemption Price per share	Issued and Outstanding	Net Proceeds	Issued and Outstanding	Net Proceeds
Series A	\$ 0.6388	\$ 25.00	4,866,814	\$ 95	3,864,636	\$ 95
Series B	Floating	\$ 25.00	1,133,186	\$ 52	2,135,364	\$ 52
Series C	\$ 1.1802	\$ 25.00	10,000,000	\$ 245	10,000,000	\$ 245
Series E	\$ 1.1250	\$ 25.75	5,000,000	\$ 122	5,000,000	\$ 122
Series F	\$ 1.0625	\$ 25.00	8,000,000	\$ 195	8,000,000	\$ 195
Series H	\$ 1.2250	\$ 25.00	12,000,000	\$ 295	12,000,000	\$ 295
Total			41,000,000	\$ 1,004	41,000,000	\$ 1,004

Characteristics of the First Preferred Shares:

First Preferred Shares (1)(2)	Initial Yield (%)	Current Annual Dividend (\$)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value (\$)	Right to Convert on a one for one basis
Fixed rate reset (3)(4)						
Series A (5)(6)	4.400	0.5456	1.84	August 15, 2025	25.00	Series B
Series C	4.100	1.1802	2.65	August 15, 2023	25.00	Series D
Series F (7)(8)	4.202	1.0505	2.63	February 15, 2025	25.00	Series G
Minimum rate reset (3)(4)						
Series B (9)	2.393	Floating	1.84	August 15, 2025	25.00	Series A
Series H	4.900	1.2250	4.90	August 15, 2023	25.00	Series I
Perpetual fixed rate						
Series E (10)	4.500	1.1250			25.75	

(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 Preferred 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 redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying \$25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent) and for Series B equals the Government of Treasury Bill Rate on the applicable reset date, plus 1.84 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 Redeemable First Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series D, Series G and Series I shares without the consent of the holder every five years thereafter for cash, in whole or in part at a price of \$25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and \$25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2023, February 15, 2020 and August 15, 2023, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.

(5) The annual fixed dividend per share for First Preferred Shares, Series A was reset from \$0.6388 to \$0.5456 for the five-year period from and including August 15, 2020.

(6) On July 9, 2020, Emera announced it would not redeem the Cumulative Rate Reset Preferred Shares, Series A or the Cumulative Floating Rate First Preferred Shares, Series B. On August 17, 2020, Emera announced 128,610 of its 3,864,636 issued and outstanding Series A Shares were tendered for conversion into Series B Shares and 1,130,788 of its 2,135,364 issued and outstanding Series B Shares were tendered for conversion into Series A Shares, all on a one-for-one basis. As a result of the conversion, Emera has 4,866,814 Series A Shares and 1,133,186 Series B Shares issued and outstanding.

(7) On January 7, 2020, Emera announced it would not redeem the 8,000,000 Cumulative Rate Reset First Preferred Shares, Series F Shares. The holders of the Series F Shares have the right, at their option, to convert all or any of their Series F Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series G of the Company on February 15, 2020, or to continue to hold their Series F Shares. On February 6, 2020, Emera announced that, after having taken into account all conversion notices received from holders, no First Preferred Shares, Series F Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series G Shares.

(8) The annual fixed dividend per share for First Preferred Shares, Series F was reset from \$1.0625 to \$1.0505 for the five-year period from and including February 15, 2020.

(9) Emera announced a dividend rate of 2.021 per cent on the Series B Shares for the three-month period which commenced on August 15, 2020 and ended on (and inclusive of) November 14, 2020 (\$0.1274 per Series B Share for the quarter

(10) First Preferred Shares, Series E are redeemable at \$25.75 to August 15, 2020, decreasing \$0.25 each year until August 15, 2022 and \$25.00 per share thereafter.

First Preferred 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 is deducted on the Consolidated Statements of Income before arriving at "Net earnings attributable to common shareholders" and is 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.

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of Canadian dollars	December 31 2020	December 31 2019
Preferred shares of GBPC	\$ 14	\$ 14
Domlec	20	21
	\$ 34	\$ 35

Preferred shares of GBPC:

Authorized:

10,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2020		2019	
	number of shares	millions of dollars	number of shares	millions of dollars
Issued and outstanding:				
Outstanding as at December 31	10,000	\$ 14	10,000	\$ 14

GBPC Non-Voting Cumulative Variable Perpetual Preferred Stock:

The preferred shares are redeemable by GBPC after June 17, 2021, at \$1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually.

The Preferred Shares rank behind GBPC's current and future secured and unsecured debt and ahead of all of GBPC's current and future common stock.

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Year ended December 31 2020	2019
Changes in non-cash working capital:		
Inventory	\$ 6	\$ (19)
Receivables and other current assets	187	154
Accounts payable	55	(137)
Other current liabilities	(31)	(71)
Total non-cash working capital	\$ 217	\$ (73)

Supplemental disclosure of cash paid (received):

Interest	\$ 679	\$ 750
Income taxes	\$ (148)	\$ (107)

Supplemental disclosure of non-cash activities:

Common share dividends reinvested	\$ 199	\$ 187
Reclassification of long-term debt from current to non-current	256	-
Increase in accrued capital expenditures	\$ 17	\$ 33

31. STOCK-BASED COMPENSATION

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in Emera's Employee Common Share Purchase Plan. As of December 31, 2020, the plan allows employees to make cash contributions of a minimum of \$25 to a maximum of \$20,000 Canadian dollars or \$15,000 US dollars per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows the reinvestment of dividends for all participants except for where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares (2019 – 4 million common shares). As at December 31, 2020, Emera is in compliance with this requirement.

Compensation cost for shares issued by Emera for the year ended December 31, 2020 under the Employee Common Share Purchase Plan was \$2 million (2019 – \$1 million) and is included in OM&G on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan") or ("DRIP"), which provides an opportunity for shareholders to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends. The discount was 2 per cent in 2020. Effective with the dividend payment of August 15, 2019, the discount changed from 5 per cent to 2 per cent.

Stock-Based Compensation Plans

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 11.7 million shares. As at December 31, 2020, Emera is in compliance with this requirement.

Stock options vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

Unless a stock option has expired, vested options may be exercised within the 24 months following the option holders date of retirement or termination for other than just cause, and within six months following the date of termination for just cause, resignation or death. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

The following table shows the weighted average fair values per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

	2020	2019
Weighted average fair value per option	\$ 3.58	\$ 2.41
Expected term (1)	5 years	6 years
Risk-free interest rate (2)	1.33 %	1.82 %
Expected dividend yield (3)	4.09 %	5.10 %
Expected volatility (4)	14.10 %	14.32 %

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.

(2) Based on the Bank of Canada five-year government bond yields.

(3) Incorporates current dividend rates and historical dividend increase patterns.

(4) Estimated using the five-year historical volatility.

The following table summarizes stock option information for 2020:

	Total Options		Non-Vested Options(1)	
	Number of Options	Weighted average exercise price per share	Number of Options	Weighted average grant date fair-value
Outstanding as at December 31, 2019	2,286,550	\$ 43.31	1,549,025	\$ 2.22
Granted	501,900	60.03	501,900	3.58
Exercised	(417,968)	44.74	N/A	N/A
Vested	N/A	N/A	(654,375)	2.32
Forfeited	(102,700)	45.94	(102,700)	2.33
Options outstanding December 31, 2020	2,267,782	\$ 46.62	1,293,850	\$ 2.69
Options exercisable December 31, 2020 (2)(3)	973,932	\$ 42.08		

(1) As at December 31, 2020, there was \$2 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 3 years (2019 - \$2 million, 2 years).

(2) As at December 31, 2020, the weighted average remaining term of vested options was 6 years with an aggregate intrinsic value of \$12 million (2019 - 6 years, \$11 million).

(3) As at December 31, 2020, the fair value of options that vested in the year was \$2 million (2019 - \$2 million).

Compensation cost recognized for stock options for the year ended December 31, 2020 was \$1 million (2019 – \$1 million), which is included in OM&G on the Consolidated Statements of Income.

As at December 31, 2020, cash received from option exercises was \$19 million (2019 – \$97 million). The total intrinsic value of options exercised for the year ended December 31, 2020 was \$6 million (2019 – \$32 million). The range of exercise prices for the options outstanding as at December 31, 2020 was \$32.06 to \$60.03 (2019 – \$32.06 to \$46.39).

Share Unit Plans

The Company has Deferred Share Unit Plan ("DSU"), Performance Share Unit Plan ("PSU") and Restricted Share Unit Plan ("RSU") plans and the liabilities are marked-to-market at the end of each period based on an average common share price at the end of the period.

Deferred Share Unit Plans

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by Emera's closing common share price on the date DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2020 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2019	704,597	\$ 34.69	531,454	\$ 39.96
Granted including DRIP	84,790	47.74	93,008	51.65
Exercised	(127,389)	30.50	(33,338)	41.89
Outstanding and exercisable as at December 31, 2020	661,998	\$ 37.17	591,124	\$ 41.69

Compensation cost recognized for employee and director DSU's for the year ended December 31, 2020 was \$2 million (2019 – \$24 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were \$1 million (2019 – \$7 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2020 for employees was \$36 million (2019 - \$40 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2020 for directors was \$32 million (2019 - \$30 million). Cash payments made during the year ended December 31, 2020 associated with the DSU plan was \$11 million (2019 - \$22 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee PSUs for the year ended December 31, 2020 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2019	1,381,100	\$ 45.37	\$ 88
Granted including DRIP	271,185	53.14	
Exercised	(445,066)	45.41	
Forfeited	(80,690)	46.25	
Outstanding as at December 31, 2020	1,126,529	\$ 47.16	\$ 68

Compensation cost recognized for the PSU plan for the year ended December 31, 2020 was \$27 million (2019 – \$34 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were \$7 million (2019 – \$9 million). Cash payments made during the year ended December 31, 2020 associated with the PSU plan was \$29 million (2019 – \$7 million).

Restricted Share Unit Plan

In 2020, Emera introduced an RSU plan, where certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee RSUs for the year ended December 31, 2020 is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2019	-	\$ -	\$ -
Granted including DRIP	171,908	54.62	
Forfeited	(5,633)	54.62	
Outstanding as at December 31, 2020	166,275	\$ 54.62	\$ 10

Compensation cost recognized for the RSU plan for the year ended December 31, 2020 was \$4 million (2019 – nil). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were \$1 million (2019 – nil). Cash payments made during the year ended December 31, 2020 associated with the RSU plan was nil (2019 – nil).

32. VARIABLE INTEREST ENTITIES

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the 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 it has authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording 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 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	December 31, 2020		December 31, 2019	
	Total	Maximum exposure to	Total	Maximum
millions of Canadian dollars	assets	loss	assets	exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	\$ 547	\$ 16	\$ 554	\$ 23

33. 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.

34. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 16, 2021, the date the financial statements were issued.

35. SUPPLEMENTAL FINANCIAL INFORMATION

On June 16, 2016, Emera US Finance LP, (in such capacity, the “Issuer”), issued \$3.25 billion USD senior unsecured notes (“U.S. Notes”). The U.S. Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera (in such capacity, the “Parent Company”) and Emera US Holdings Inc. (in such capacity, the “Guarantor Subsidiaries”). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP.

The following condensed consolidated financial statements present the results of operations, financial position and cash flows of the Parent Company, Subsidiary Issuer, Guarantor Subsidiaries and all other Non-guarantor Subsidiaries independently and on a consolidated basis.

Our guarantors were not determined using geographic, service line or other similar criteria, and as a result, the “Parent”, “Subsidiary Issuer”, “Guarantor Subsidiaries” and “Non-guarantor Subsidiaries” columns each include portions of our domestic and international operations. Accordingly, this basis of presentation is not intended to present our financial condition, results of operations or cash flows for any purpose other than to comply with the specific requirements for guarantor reporting.

Emera Incorporated

Condensed Consolidated Statements of Income

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
For the year ended December 31, 2020						
Operating revenues	\$ (1)	\$ -	\$ 3,456	\$ 2,070	\$ (19)	\$ 5,506
Operating expenses	51	-	2,640	1,688	(20)	4,359
Income (loss) from equity investments and subsidiaries	1,049	-	1	147	(1,048)	149
Other income (expenses), net	20	-	687	1	-	708
Interest expense, net (1)	48	(37)	448	220	-	679
Income (loss) before provision for income taxes	969	37	1,056	310	(1,047)	1,325
Income tax expense (recovery)	(14)	(1)	348	7	1	341
Net income (loss)	983	38	708	303	(1,048)	984
Non-controlling interest in subsidiaries	-	-	-	-	1	1
Preferred stock dividends	45	-	-	1	(1)	45
Net income (loss) attributable to common shareholders	\$ 938	\$ 38	\$ 708	\$ 302	\$ (1,048)	\$ 938
Comprehensive income (loss) of Emera Incorporated	\$ 809	\$ 35	\$ 575	\$ 257	\$ (867)	\$ 809
For the year ended December 31, 2019						
Operating revenues	\$ -	\$ -	\$ 4,125	\$ 2,029	\$ (43)	\$ 6,111
Operating expenses	31	-	3,084	1,695	(42)	4,768
Income (loss) from equity investments and subsidiaries	753	-	2	151	(752)	154
Other income (expenses), net	21	-	22	(11)	(20)	12
Interest expense, net (1)	75	(40)	481	222	-	738
Income (loss) before provision for income taxes	668	40	584	252	(773)	771
Income tax expense (recovery)	(40)	11	60	30	-	61
Net income (loss)	708	29	524	222	(773)	710
Non-controlling interest in subsidiaries	-	-	-	-	2	2
Preferred stock dividends	45	-	19	3	(22)	45
Net income (loss) attributable to common shareholders	\$ 663	\$ 29	\$ 505	\$ 219	\$ (753)	\$ 663
Comprehensive income (loss) of Emera Incorporated	\$ 465	\$ 14	\$ 102	\$ 205	\$ (321)	\$ 465

(1) Interest expense is net of interest revenue.

Emera Incorporated

Condensed Consolidated Balance Sheets

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
As at December 31, 2020						
Assets						
Current assets	\$ 121	\$ 10	1,216	\$ 1,010	\$ (179)	\$ 2,178
Property, plant and equipment	21	-	14,356	5,164	(6)	19,535
Other assets						
Regulatory assets	-	-	520	899	-	1,419
Goodwill	3	-	5,648	69	-	5,720
Other long-term assets	12,522	4,591	130	3,254	(18,115)	2,382
Total other assets	12,525	4,591	6,298	4,222	(18,115)	9,521
Total assets	\$ 12,667	\$ 4,601	\$ 21,870	\$ 10,396	\$ (18,300)	\$ 31,234
Liabilities and Equity						
Current liabilities	\$ 554	\$ 2,024	\$ 4,121	\$ 723	\$ (2,547)	\$ 4,875
Long-term liabilities						
Long-term debt	2,210	2,513	4,026	3,590	-	12,339
Deferred income taxes	-	2	852	761	14	1,629
Regulatory liabilities	-	-	1,747	85	-	1,832
Other long-term liabilities	700	-	4,510	1,666	(5,555)	1,321
Total long-term liabilities	2,910	2,515	11,135	6,102	(5,541)	17,121
Total Emera Incorporated equity	9,203	62	6,614	3,550	(10,225)	9,204
Non-controlling interest in subsidiaries	-	-	-	21	13	34
Total equity	9,203	62	6,614	3,571	(10,212)	9,238
Total liabilities and equity	\$ 12,667	\$ 4,601	\$ 21,870	\$ 10,396	\$ (18,300)	\$ 31,234
As at December 31, 2019						
Assets						
Current assets	\$ 96	\$ 27	1,486	\$ 1,171	\$ (294)	\$ 2,486
Property, plant and equipment	23	-	13,099	5,040	5	18,167
Other assets						
Regulatory assets	-	-	519	912	-	1,431
Goodwill	3	-	5,762	70	-	5,835
Other long-term assets	11,994	3,856	1,739	3,289	(16,955)	3,923
Total other assets	11,997	3,856	8,020	4,271	(16,955)	11,189
Total assets	\$ 12,116	\$ 3,883	\$ 22,605	\$ 10,482	\$ (17,244)	\$ 31,842
Liabilities and Equity						
Current liabilities	\$ 542	\$ 12	\$ 3,699	\$ 992	\$ (1,079)	\$ 4,166
Long-term liabilities						
Long-term debt	2,978	3,534	8,829	4,547	(6,209)	13,679
Deferred income taxes	-	3	515	767	-	1,285
Regulatory liabilities	-	-	1,793	93	-	1,886
Other long-term liabilities	38	-	1,697	511	(21)	2,225
Total long-term liabilities	3,016	3,537	12,834	5,918	(6,230)	19,075
Total Emera Incorporated equity	8,558	334	6,072	3,551	(9,949)	8,566
Non-controlling interest in subsidiaries	-	-	-	21	14	35
Total equity	8,558	334	6,072	3,572	(9,935)	8,601
Total liabilities and equity	\$ 12,116	\$ 3,883	\$ 22,605	\$ 10,482	\$ (17,244)	\$ 31,842

Emera Incorporated

Condensed Consolidated Statements of Cash Flows

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
As at December 31, 2020						
Net cash provided by (used in) by operating activities	\$ 365	\$ 36	\$ 1,277	\$ 486	\$ (527)	\$ 1,637
Investing activities						
Additions to property, plant and equipment	(1)	-	(2,150)	(472)	-	(2,623)
Proceeds on disposal of assets	-	-	1,401	-	-	1,401
Other investing activities	(118)	265	546	100	(795)	(2)
Net cash provided by (used in) investing activities	(119)	265	(203)	(372)	(795)	(1,224)
Financing activities						
Change in short-term debt, net	(6)	-	107	(5)	-	96
Proceeds from long-term debt	-	-	173	429	(174)	428
Retirement of long-term debt	-	-	(705)	(87)	279	(513)
Net borrowings (repayments) under committed credit facilities	(82)	-	8	(157)	28	(203)
Issuance of common and preferred stock	285	(241)	(3)	53	191	285
Dividends paid	(454)	(66)	(80)	(379)	525	(454)
Other financing activities	(18)	(4)	(494)	32	473	(11)
Net cash provided by (used in) financing activities	(275)	(311)	(994)	(114)	1,322	(372)
Effect of exchange rate changes on cash, cash equivalents, restricted cash and assets held for sale	18	(8)	(70)	(1)	-	(61)
Net increase (decrease) in cash, cash equivalents, restricted cash and assets held for sale	(11)	(18)	10	(1)	-	(20)
Cash, cash equivalents, and restricted cash, beginning of year	1	19	87	167	-	274
Cash, cash equivalents, restricted cash and assets held for sale, end of year	\$ (10)	\$ 1	\$ 97	\$ 166	\$ -	\$ 254

Emera Incorporated **Condensed Consolidated Statements of Cash Flows (Continued)**

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
As at December 31, 2019						
Net cash provided by (used in) operating activities	\$ 133	\$ 33	\$ 1,100	\$ 279	\$ (20)	\$ 1,525
Investing activities						
Additions to property, plant and equipment	(2)	-	(1,973)	(520)	-	(2,495)
Net purchase of investments subject to significant influence	-	-	(3)	-	-	(3)
Proceeds on disposal of assets significant influence and held-for-trading common shares	-	-	818	57	-	875
Other investing activities	(402)	595	774	(1)	(960)	6
Net cash provided by (used in) investing activities	(404)	595	(384)	(464)	(960)	(1,617)
Financing activities						
Change in short-term debt, net	399	-	(9)	23	-	413
Proceeds from long-term debt	-	-	(6)	552	520	1,066
Retirement of long-term debt	(225)	(664)	(65)	(166)	17	(1,103)
Net borrowings (repayments) under committed credit facilities	146	-	(11)	(225)	(28)	(118)
Issuance of common and preferred stock	203	-	(620)	58	562	203
Dividends paid	(423)	-	(19)	(138)	157	(423)
Other financing activities	(1)	-	138	87	(248)	(24)
Net cash provided by (used in) financing activities	99	(664)	(592)	191	980	14
Effect of exchange rate changes on cash, cash equivalents and restricted cash	147	(3)	(141)	(23)	-	(20)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(25)	(39)	(17)	(17)	-	(98)
Cash, cash equivalents and restricted cash, beginning of year	20	58	104	190	-	372
Cash, cash equivalents and restricted cash, end of year	\$ (5)	\$ 19	\$ 87	\$ 173	\$ -	\$ 274