Management’s Discussion & Analysis

As at February 14, 2020

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments (“Emera”) during the fourth quarter of 2019 relative to the same quarter in 2018; the full year of 2019 relative to 2018 and selected financial information for 2017; and its financial position as at December 31, 2019 relative to December 31, 2018. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2019. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”).

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations. The five new reportable segments are:

- **Florida Electric Utility**, which consists of Tampa Electric;
- **Canadian Electric Utilities**, which includes Nova Scotia Power Inc. and Emera Newfoundland & Labrador Holdings Inc., a holding company with equity investments in NSP Maritime Link Inc. and Labrador-Island Link Limited Partnership;
- **Other Electric Utilities**, which includes Emera Maine and Emera (Caribbean) Incorporated;
- **Gas Utilities and Infrastructure**, which includes Peoples Gas System, New Mexico Gas Company, Inc., SeaCoast Gas Transmission, LLC; Emera Brunswick Pipeline Company Limited and an equity investment in Maritimes & Northeast Pipeline; and
- **Other**, which includes Emera Energy and corporate holding and financing companies. In 2019, the Company completed the sale of assets previously included in this segment, including the sale of Emera Energy’s New England Gas Generating (“NEGG”) and Bayside facilities, and Emera Utility Services (“EUS”) equipment and inventory.

All comparative reporting segment financial information for the three months and year ended December 31, 2018 has been restated with no impact to reported consolidated results.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. Emera's rate-regulated subsidiaries and investments include:

Emera Rate-Regulated Subsidiary or Equity Investment	**Accounting Policies Approved/Examined By**
Subsidiary	
Tampa Electric – Electric Division of Tampa Electric Company ("TEC")	Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC")
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Emera Maine	Maine Public Utilities Commission ("MPUC") and FERC
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Dominica Electricity Services Ltd. ("Domlec")	Independent Regulatory Commission, Dominica ("IRC")
Peoples Gas System ("PGS") – Gas Division of TEC	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	Canadian Energy Regulator ("CER", formerly the National Energy Board)
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB")
St. Lucia Electricity Services Limited ("Lucelec")	National Utility Regulatory Commission ("NURC")
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP")	CER and FERC

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Other Electric Utilities and Gas Utilities and Infrastructure sections of the MD&A, which are reported in US dollars ("USD"), unless otherwise stated.

Additional information related to Emera, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com.

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FORWARD-LOOKING INFORMATION

This MD&A contains “forward-looking information” and statements which reflect the current view with respect to the Company’s expectations regarding future growth, results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes within the meaning of applicable Canadian securities laws. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecast”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “targets”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the “Business Overview and Outlook” section of the MD&A and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; pricing and timing of select asset sales; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

INTRODUCTION AND STRATEGIC OVERVIEW

Based in Halifax, Nova Scotia, Emera owns and operates cost-of-service rate-regulated electric and gas utilities in Canada, the United States and the Caribbean. Cost-of-service utilities provide essential gas and electric services in designated territories under franchises and are overseen by regulatory authorities. Emera's strategic focus is to safely deliver cleaner, affordable and reliable energy to its customers.

Emera's investment in rate-regulated businesses is concentrated in Florida and Nova Scotia. These service areas have experienced stable regulatory policies and economic conditions.

Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), and the amount of equity in the capital structure and the return on that equity ("ROE") as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera has a $6.9 billion capital investment plan over the 2020-to-2022 period and the potential for additional capital opportunities of $500 million to $1 billion over the forecast period, resulting in a forecasted rate base growth of 7 per cent through to 2022. This plan includes significant investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. This planned capital investment is being funded primarily through internally generated cash flows and debt raised at the operating company level. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2022. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time.

Seasonal patterns and other weather events affect demand and operating costs. Similarly, mark-to-market adjustments and foreign currency exchange can have a material impact on financial results for a specific period. Emera's consolidated net income and cash flows are impacted by movements in the US dollar relative to the Canadian dollar and benefit from a weaker Canadian dollar. Emera may hedge both transactional and translational exposure. These impacts, as well as the timing of capital investment and other factors mean that results in any one quarter are not necessarily indicative of results in any other quarter or for the year as a whole.

Energy markets worldwide are facing significant change and Emera is well positioned to respond to shifting customer demands, complex regulatory environments and the trend towards de-carbonization. Renewable generation and battery storage are becoming both more affordable and efficient. Climate change and extreme weather are shaping how utilities operate and how they invest in infrastructure. There is also an overall need to replace aging infrastructure and further enhance reliability. Emera sees opportunity in these trends. Emera's strategy is to fund investments in renewable and technology assets which protect the environment and benefit customers through fuel or operating cost savings.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the Maritime Link in Atlantic Canada, the ongoing construction of solar generation at Tampa Electric, and the modernization of the Big Bend Power Station at Tampa Electric. Emera's utilities are also investing in reliability projects and replacing aging infrastructure. All of these projects demonstrate Emera's strategy of finding cleaner ways to meet the energy needs of its customers while keeping rates affordable.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships with regulators, stakeholders and the communities where we operate.

NON-GAAP FINANCIAL MEASURES

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. These measures are discussed and reconciled below.

Adjusted Net Income

Emera calculates an adjusted net income measure by excluding the effect of mark-to-market ("MTM") adjustments, the revaluation of US non-regulated net deferred income tax assets as a result of US tax reform in Q4 2017 and the GBPC impairment charge recognized in Q4 2019.

The MTM adjustments are a result of the following:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company LLC ("Bear Swamp");
- the amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline; and
- the mark-to-market adjustments related to equity securities held in BLPC and Emera Reinsurance, a captive reinsurance company in the Other segment.

Management believes excluding from net income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows and ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these mark-to-market adjustments for evaluation of performance and incentive compensation.

Refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Other Electric Utilities and Other segments, for further details on mark-to-market adjustments.

In Q3 2019, Hurricane Dorian, a category 5 hurricane, struck Grand Bahama Island causing significant damage across the island. In Q4 2019, the Company recognized a non-cash impairment charge 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. Management believes excluding from net income the effect of this charge better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. Refer to the "Significant Items Affecting Earnings", "Developments" and "Financial Highlights – Other Electric Utilities" sections, for further details on this GBPC impairment charge.

The following reconciles reported net income attributable to common shareholders, to adjusted net income attributable to common shareholders; and reported earnings per common share – basic, to adjusted earnings per common share – basic:

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2019	2018	**2019**	2018	2017
Net income attributable to common shareholders	**$ 193**	$ 231	**$ 663**	$ 710	$ 266
GBPC impairment charge	**$ (34)**	$ -	**$ (34)**	$ -	$ -
Revaluation of US non-regulated deferred income taxes	**$ -**	$ -	**$ -**	$ -	$ (317)
After-tax mark-to-market gain	**$ 82**	$ 64	**$ 76**	$ 39	$ 59
Adjusted net income attributable to common shareholders	**$ 145**	$ 167	**$ 621**	$ 671	$ 524
Earnings per common share – basic	**$ 0.79**	$ 0.98	**$ 2.76**	$ 3.05	$ 1.25
Adjusted earnings per common share – basic	**$ 0.60**	$ 0.71	**$ 2.59**	$ 2.88	$ 2.46

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-GAAP financial measure used by Emera. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital and finance working capital requirements.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to adjusted net income calculations described above, this measure represents EBITDA absent the income effect of Emera's mark-to-market and amortization adjustments, and the GBPC impairment charge discussed above.

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies but, in management's view, appropriately reflect Emera's specific operating performance. These measures are not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance.

The following is a reconciliation of reported net income to EBITDA and Adjusted EBITDA:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2019	2018	**2019**	2018	2017
Net income (1)	**$ 192**	$ 231	**$ 710**	$ 747	$ 299
Interest expense, net	**181**	186	**738**	713	698
Income tax expense	**43**	40	**61**	69	520
Depreciation and amortization	**225**	229	**903**	916	856
EBITDA	**641**	686	**2,412**	2,445	2,373
GBPC impairment charge	**(34)**	-	**(34)**	-	-
Mark-to-market gain, excluding income tax and interest	**118**	94	**107**	58	78
Adjusted EBITDA	**$ 557**	$ 592	**$ 2,339**	$ 2,387	$ 2,295

(1) Net income is income before Non-controlling interest in subsidiaries and Preferred stock dividends.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

2019

GBPC Hurricane Dorian Restoration

On September 1, 2019, Hurricane Dorian struck Grand Bahama as a Category 5 hurricane, causing significant damage across the island. Emera's 2019 earnings decreased by approximately $62 million ($0.26 per common share), as a result of the impact of the hurricane, as detailed below.

In Q4 2019, Emera recognized a GBPC impairment charge of $34 million, including $30 million related to goodwill 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. This non-cash charge was recorded as a "GBPC impairment charge" in the Consolidated Statements of Income. Refer to note 21 to the consolidated financial statements for the year ended December 31, 2019 for further information.

In addition, GBPC's earnings for the full year decreased by $13 million ($0.05 per common share) due to reduced load as a result of the storm. Finally, Emera recorded a corporate loss of $15 million ($0.06 per common share) in 2019, in the Other segment, for the corporate share of the unrecoverable loss on GBPC's facilities.

Refer to the "Developments" section for further details on Hurricane Dorian.

Earnings Impact of After-Tax Mark-to-Market Gains and Losses

After-tax mark-to-market gains increased $18 million to $82 million in Q4 2019, compared to $64 million in Q4 2018. This increase was due to changes in existing positions on gas contracts, partially offset by higher amortization of gas transportation assets in Q4 2019 in Emera Energy. For the year ended December 31, 2019, after-tax mark-to-market gains increased $37 million to $76 million in 2019, compared to $39 million in 2018. This increase was due to changes in existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019, compared to 2018, partially offset by higher amortization of gas transportation assets in 2019 in Emera Energy.

2018

Florida State Tax Apportionment

In Q3 2018, Emera received approval from the Florida Department of Economic Opportunity to change its Florida state tax apportionment factors. This change resulted in the Company recording a tax benefit of approximately $23 million, or $0.10 per common share, as a result of the remeasurement of certain deferred tax balances.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
Adjusted Net Income	**2019**	2018	**2019**	2018	2017
Florida Electric Utility	**$ 80**	$ 83	**$ 419**	$ 381	$ 354
Canadian Electric Utilities	**58**	44	**229**	218	203
Other Electric Utilities	**14**	25	**76**	89	77
Gas Utilities and Infrastructure	**51**	43	**183**	136	109
Other	**(58)**	(28)	**(286)**	(153)	(219)
Adjusted net income attributable to common shareholders	**$ 145**	$ 167	**$ 621**	$ 671	$ 524
GBPC impairment charge	**(34)**	-	**(34)**	-	-
Revaluation of US non-regulated deferred income taxes	**-**	-	**-**	-	(317)
After-tax mark-to-market gain	**82**	64	**76**	39	59
Net income attributable to common shareholders	**$ 193**	$ 231	**$ 663**	$ 710	$ 266

The following table highlights the significant changes in adjusted net income from 2018 to 2019:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2018	**$ 167**	**$ 671**
Florida Electric Utility - decreased earnings in Q4 2019 due to unfavourable weather in Florida. Year-over-year increased earnings due to higher contribution from solar investments and customer growth, partially offset by higher depreciation and interest	(3)	38
Gas Utilities and Infrastructure - increased earnings due to favourable weather in New Mexico, customer growth at PGS and lower depreciation and amortization at PGS	-	28
NMGC tax benefit related to change in treatment of net operating loss ("NOL") carryforwards, and Q2 2019 recognition of tax reform benefits, of which $8 million relates to 2018	8	19
Canadian Electric Utilities - NSPI earnings increased due to decreased income taxes and lower pension costs, partially offset by increased depreciation. In addition, year-over-year, increased operating maintenance and general expenses ("OM&G") were partially offset by increased non-fuel revenues. Increased income from equity investments due to timing of revenue and operational costs in NSPML and higher equity investment in LIL	14	11
Gain on sale of property in Florida	-	10
Transaction costs related to the pending sale of Emera Maine	(1)	(7)
2018 recognition of Florida state tax apportionment benefit	-	(23)
Impact of Hurricane Dorian related to GBPC. Refer to the "Significant items Affecting earnings" and "Developments" sections	(12)	(28)
Decreased earnings from Emera Energy Generation due to the sale of New England Gas Generating Facilities ("NEGG") and Bayside generation facility	(21)	(43)
Decreased earnings at Emera Energy Services	(6)	(49)
Other variances	(1)	(6)
Adjusted net income – 2019	**$ 145**	**$ 621**

Refer to the "Financial Highlights" section for further details of reportable segment contributions.

For the millions of Canadian dollars			Year ended December 31
	2019	2018	2017
Operating cash flow before changes in working capital	**$ 1,598**	$ 1,806	$ 1,297
Change in working capital	**(73)**	(116)	(104)
Operating cash flow	**$ 1,525**	$ 1,690	$ 1,193
Investing cash flow	**$ (1,617)**	$ (2,190)	$ (1,761)
Financing cash flow	**$ 14**	$ 344	$ 593

As at millions of Canadian dollars	**2019**	2018	December 31 2017
Total assets	**$ 31,842**	$ 32,314	$ 28,806
Total long-term debt (including current portion) (1)	**$ 14,180**	$ 15,411	$ 13,881

(1) Excludes Emera Maine balances classified as held for sale as at December 31, 2019. Refer to the "Developments" section and note 4 in the consolidated financial statements for further details.

Refer to the "Consolidated Cash Flow Highlights" section for further discussion of cash flow.

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Variance	Year ended December 31		Variance	Year ended December 31
	2019	2018		**2019**	2018		2017
Operating revenues	**$ 1,616**	$ 1,799	$ (183)	**$ 6,111**	$ 6,524	$ (413)	$ 6,226
Operating expenses	**1,237**	1,368	131	**4,768**	5,126	358	4,808
Income from operations	**379**	431	(52)	**1,343**	1,398	(55)	1,418
Income from equity investments	**36**	33	3	**154**	154	-	124
Other income (expenses), net	**1**	(7)	8	**12**	(23)	35	(25)
Interest expense, net	**181**	186	5	**738**	713	(25)	698
Income tax expense	**43**	40	(3)	**61**	69	8	520
Net income	**192**	231	(39)	**710**	747	(37)	299
Net income attributable to common shareholders	**193**	231	(38)	**663**	710	(47)	266
GBPC impairment charge	**(34)**	-	(34)	**(34)**	-	(34)	-
Revaluation of US non-regulated deferred income taxes	**-**	-	-	**-**	-	-	(317)
After-tax mark-to-market gain	**82**	64	18	**76**	39	37	59
Adjusted net income attributable to common shareholders	**$ 145**	$ 167	$ (22)	**$ 621**	$ 671	$ (50)	$ 524
Earnings per common share – basic	**$ 0.79**	$ 0.98	$ (0.19)	**$ 2.76**	$ 3.05	$ (0.29)	$ 1.25
Earnings per common share – diluted	**$ 0.80**	$ 0.98	$ (0.18)	**$ 2.76**	$ 3.04	$ (0.28)	$ 1.24
Adjusted earnings per common share – basic	**$ 0.60**	$ 0.71	$ (0.11)	**$ 2.59**	$ 2.88	$ (0.29)	$ 2.46
Dividends per common share declared	**$ -**	$ -	$ -	**$ 2.3750**	$ 2.2825	$ 0.0925	$ 2.1325
Adjusted EBITDA	**$ 557**	$ 592	$ (35)	**$ 2,339**	$ 2,387	$ (48)	$ 2,295

Operating Revenues

For the fourth quarter of 2019, operating revenues decreased $183 million compared to the fourth quarter in 2018. Absent increased mark-to-market gains of $22 million, operating revenues decreased $205 million due to:

- $130 million decrease in the Other segment due to the sale of NEGG and Bayside;
- $38 million decrease at Florida Electric Utility due to a reduction in base rates as a result of US tax reform and lower clause revenues;
- $21 million decrease at NSPI due to decreased industrial and commercial class sales volume and decreased volume due to weather; and
- $14 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and higher fixed cost commitments for gas transportation and storage assets.

For the year ended December 31, 2019, operating revenues decreased $413 million compared to 2018. Absent increased mark-to-market gains of $48 million, operating revenues decreased by $461 million due to:

- $327 million decrease in the Other segment due to the sale of NEGG and Bayside;
- $137 million decrease at Florida Electric Utility due to lower base rates as a result of US tax reform;
- $84 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and higher fixed cost commitments for gas transportation and storage assets; and
- $20 million decrease in PGS due to lower off-system sales and lower base rates as a result of US tax reform, and lower clause-related revenues at PGS and NMGC.

These impacts were partially offset by increases of:

- $65 million at Florida Electric Utility as a result of a weaker Canadian dollar and higher base revenues related to in-service of solar generation projects and customer growth; and
- $41 million at Gas Utilities and Infrastructure as a result of NMGC's recognition of tax reform benefits from January 1, 2018 to June 30, 2019, favourable weather in New Mexico, customer growth at PGS and the impact of a weaker Canadian dollar.

Operating Expenses

For the fourth quarter of 2019, operating expenses decreased $131 million compared to the fourth quarter of 2018. Absent the $34 million GBPC impairment charge, operating expenses decreased by $165 million due to:

- $96 million decrease in the Other segment primarily due to the sale of NEGG and Bayside;
- $34 million decrease at Florida Electric Utility as a result of decreased OM&G due to the regulatory agreement to net storm costs and tax reform benefits in 2018 and lower fuel costs;
- $17 million decrease at Gas Utilities and Infrastructure due to lower commodity costs in PGS and New Mexico; and
- $16 million decrease at Canadian Electric Utilities primarily due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment, partially offset by increased fuel for generation and purchased power and depreciation.

For the year ended December 31, 2019, operating expenses decreased $358 million compared to 2018. Absent decreased mark-to-market gains of $7 million, and the $34 million GBPC impairment charge, operating expenses decreased $399 million due to:

- $262 million decrease in the Other segment as a result of the sale of NEGG and Bayside;
- $126 million decrease at Florida Electric Utility as a result of decreased OM&G expenses due to the regulatory agreement to net storm costs and tax reform benefits in 2018 and lower fuel costs;
- $48 million decrease at Gas Utilities and Infrastructure due to lower commodity costs in PGS and New Mexico; and
- $44 million decrease at Canadian Electric Utilities primarily due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment.

These impacts were partially offset by an increase of:

- $63 million at Canadian Electric Utilities primarily due to increased fuel costs as a result of commodity pricing, higher OM&G and higher depreciation.

Other Income (Expenses), Net

The increase in other income (expenses), net for the fourth quarter in 2019 was primarily due to lower pension costs at NSPI, partially offset by the corporate loss recorded by Emera for the corporate share of the unrecoverable loss on GBPC facilities resulting from the impact of Hurricane Dorian, and transaction costs for the pending sale of Emera Maine. For the year ended December 31, 2019, absent increased mark-to-market gains, the increase was also due to the gain on sale of property in Florida.

Interest Expense

Interest expense, net for the fourth quarter in 2019 was consistent with the same period in 2018. The increase in interest expense, net for the year ended December 31, 2019, compared to 2018 was primarily due to higher borrowings at Florida Electric Utility and a weaker Canadian dollar.

Income Tax Expense

Income tax expense for the fourth quarter and for the year ended December 31, 2019, was consistent with the same periods in 2018.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the fourth quarter of 2019, net income attributable to common shareholders was favourably impacted by the $18 million increase in after-tax mark-to-market gains, primarily related to Emera Energy and unfavourably impacted by the GBPC impairment charge of $34 million. Absent favourable mark-to-market changes and the GBPC impairment charge, adjusted net income attributable to common shareholders decreased $22 million. The decrease was due to lower contributions from Emera Energy (which includes lower contribution due to the sale of NEGG in Q1 2019) and the impact of Hurricane Dorian related to GBPC, partially offset by higher contributions from Canadian Electric Utilities and Gas Utilities and Infrastructure.

For the year ended December 31, 2019, net income attributable to common shareholders was favourably impacted by the $37 million increase in after-tax mark-to-market gains primarily related to Emera Energy and unfavourably impacted by the GBPC impairment charge of $34 million. Absent favourable mark-to-market changes and the GBPC impairment charge, adjusted net income attributable to common shareholders decreased $50 million. The decrease was due to lower contributions from Emera Energy (which includes the lower contribution due to the sale of NEGG in Q1 2019), the 2018 recognition of Florida state tax apportionment benefits, the impact of Hurricane Dorian related to GBPC and transaction costs related to the pending sale of Emera Maine. These were partially offset by higher contribution from Florida Electric Utility, the impact of a weaker Canadian dollar, NMGC's recognition of tax reform benefits, increased contribution from the Gas Utilities and Infrastructure segment and a gain on sale of property in Florida.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share – basic were lower for the fourth quarter and the year ended December 31, 2019 due to decreased earnings as discussed above and the impact of the increase in the weighted average common shares outstanding.

Effect of Foreign Currency Translation

Emera operates internationally, including in Canada, the US and various Caribbean countries. As such, the Company generates revenues and incurs expenses denominated in local currencies which are translated into Canadian dollars for financial reporting. Changes in translation rates, particularly in the value of the US dollar against the Canadian dollar, can positively or adversely affect results.

Earnings from Emera’s foreign operations are translated into Canadian dollars. In general, Emera’s earnings benefit from a weakening Canadian dollar and are adversely impacted by a strengthening Canadian dollar. The impact of foreign exchange in any period is driven by rate changes, the timing of earnings from foreign operations during the period, and the percentage of earnings from foreign operations in the period.

Results of foreign operations are translated at the weighted average rate of exchange and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/US exchange rates for 2019 and 2018 are as follows:

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Weighted average CAD/USD	**$ 1.32**	$ 1.32	**$ 1.33**	$ 1.30
Period end CAD/USD exchange rate	**$ 1.30**	$ 1.36	**$ 1.30**	$ 1.36

CAD exchange rates decreased earnings by $1 million and had minimal impact on adjusted earnings in Q4 2019, compared to Q4 2018. Weakening of the CAD increased earnings and adjusted earnings by $13 million in 2019, compared to 2018.

Consistent with the Company’s risk management policies, Emera partially 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. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

The table below includes Emera's significant segments whose contributions to adjusted earnings are recorded in US dollar currency.

millions of US dollars	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Florida Electric Utility	**$ 61**	$ 64	**$ 316**	$ 294
Other Electric Utilities	**10**	20	**57**	69
Gas Utilities and Infrastructure (1)	**33**	26	**115**	83
	104	110	**488**	446
Other segment (2)	**(28)**	(27)	**(159)**	(82)
Total (3)	**$ 76**	$ 83	**$ 329**	$ 364

(1) Includes US dollar net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's US dollar adjusted net income from Emera Energy Services, NEGG and Bear Swamp and interest expense on Emera Inc.'s US dollar denominated debt.
(3) Amounts above do not include the impact of mark-to-market or the GBPC impairment charge.

BUSINESS OVERVIEW AND OUTLOOK

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations.

The five new reportable segments are:

- Florida Electric Utility;
- Canadian Electric Utilities;
- Other Electric Utilities;
- Gas Utilities and Infrastructure; and
- Other.

Earnings from Emera's regulated utilities are most directly impacted by the rate of return on equity ("ROE") or rate base and capital structure approved by their regulators, prudent management of operating costs, approved recovery of regulatory deferrals, energy sales volumes including the impact of weather, and the timing and amount of capital expenditures. Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Emera's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. The electric and gas utilities' industrial customers include manufacturing facilities and other large-volume operations.

Florida Electric Utility

Florida Electric Utility consists of Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. Tampa Electric has approximately $9 billion USD of assets and approximately 779,000 customers at December 31, 2019. Tampa Electric owns 5,641 MW of generating capacity, of which 73 per cent is natural gas-fired, 19 per cent is coal and 8 per cent is solar. Tampa Electric owns 2,165 kilometres of transmission facilities and 18,990 kilometres of distribution facilities.

Tampa Electric's approved regulated ROE range 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.

Tampa Electric anticipates earning within its allowed ROE range in 2020 and expects rate base and earnings to be higher than 2019. Tampa Electric expects customer growth rates in 2020 to be consistent with 2019, reflective of economic growth in Florida. Assuming normal weather in 2020, Tampa Electric sales volumes are expected to be consistent with 2019, which benefited from favourable weather.

On December 10, 2019, the FPSC approved Tampa Electric's petition to reduce base rates and charges reflecting reduction of the state income tax rate from 5.5 per cent to 4.46 per cent retroactive from January 1, 2019. The base rate reduction of approximately $5 million USD due to customers is subject to true-up, and the actual rate reduction may vary from year to year. In addition, in January 2020, Tampa Electric refunded $12 million USD to customers as a result of the final settlement agreement related to the netting of Hurricane Irma storm costs and 2018 US tax reform benefits.

On October 3, 2019, the FPSC issued a rule to implement a storm protection 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. Subject to final approval of the FPSC rule, Tampa Electric expects to file a storm protection plan with the FPSC in Q2 2020.

As of December 31, 2019, Tampa Electric has invested approximately $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. Allowance for funds used during construction ("AFUDC") is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 554 MW or $96 million USD annually in estimated revenue requirements for in-service projects. Tampa Electric expects to file its final SoBRA petition for the January 1, 2021 tranche in 2020. Tampa Electric also intends to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects with targeted in-service dates during 2021 through 2023.

Tampa Electric expects to invest approximately $850 million USD through 2023 to modernize the Big Bend Power Station. This modernization project includes conversion of Unit 1 from coal-fired to natural gas combined-cycle technology and the early retirement of Unit 2. As of December 31, 2019, Tampa Electric has invested approximately $275 million USD in this modernization project. AFUDC is being earned on this project during construction.

In 2020, capital expenditures in the Florida Electric Utility segment are expected to be approximately $1.0 billion USD (2019 - $1.1 billion USD), including AFUDC. Capital projects include solar investments, continuation of the modernization of the Big Bend Power Station, which received final state approval on July 25, 2019, storm hardening investments, and advanced metering infrastructure ("AMI").

Canadian Electric Utilities

Canadian Electric Utilities includes NSPI, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia; and ENL, a holding company with equity investments in NSPML and LIL, two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.

NSPI

With approximately $5.5 billion of assets and approximately 523,000 customers, NSPI owns 2,441 MW of generating capacity, of which approximately 43 per cent is coal-fired; 28 per cent is natural gas and/or oil; 20 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 545 MW of capacity. NSPI will have an increase in energy from renewable sources upon delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project. Delivery of the NS Block is anticipated to commence in mid-2020. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

NSPI'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 40 per cent. NSPI anticipates earning within its allowed ROE range in 2020 and expects rate base and earnings to be higher than 2019. Assuming normal weather in 2020, NSPI sales volumes are expected to be higher. On December 6, 2019, the UARB approved NSPI's 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 (discussed in the "ENL – NSPML" section below).

NSPI is subject to environmental laws and regulations set by both the Government of Canada and the Province of Nova Scotia. NSPI continues to work with both levels of government to comply with these laws and regulations, to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated reductions will be recoverable under NSPI's regulatory framework.

The Government of Canada has laws and regulations that would compel the closure of coal plants before the end of their economic life and at the latest by 2030. The Canada-Nova Scotia Equivalency Agreement allows NSPI to achieve compliance with federal GHG emissions regulations through 2029 by meeting provincial legislative and regulatory requirements, as these requirements are deemed to be equivalent to the federal regulations. Efforts are now focused on the development of an Equivalency Agreement for 2030 and beyond recognizing equivalent outcomes between federal and provincial environmental laws and regulations. The Province's Bill 213, "*The Sustainable Development Goals Act"*, was enacted in October 2019, and includes a goal of net-zero GHG emissions by 2050. NSPI will continue to work with the provincial government on its carbon reduction goals.

NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations in 2019 and expects to receive its 2020 granted emissions allowances in Q1 2020. These 2020 allowances will be used in 2020 or allocated within the initial four-year compliance period that ends in 2022. At December 31, 2019, NSPI is on track to meet the requirements of the program. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's laws and regulations, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable under NSPI's regulatory framework.

Nova Scotia's Air Quality Regulations (the "Regulations") with respect to sulphur dioxide ("SO_2") emissions have been driving a steady decrease in SO_2 emissions since 2005. The current Regulations call for another round of decreases starting in 2020. Given the delay with Muskrat Falls, the provincial government has amended regulations for adjusted emission limits for 2020 through 2022 in order to avoid significant rate increases for customers, while continuing Nova Scotia's downward trend with SO_2 emissions. NSPI incorporated the impact of these changes into the UARB-approved fuel stability plan for this three-year period.

Although the market in Nova Scotia is otherwise mature, the transformation of energy supply to lower-emission sources has driven organic growth within NSPI as investments have been made in renewable generation and system reliability projects to further advance its “Coal to Clean” strategy. NSPI achieved carbon dioxide reductions of over 30 per cent from 2005 levels, exceeding the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change targets for a reduction of 30 per cent from 2005 levels by 2030. NSPI is on track to achieve reductions in carbon dioxide of over 55 per cent by 2030.

In 2020, NSPI expects to invest approximately $375 million (2019 - $396 million), including AFUDC, in capital projects to support system reliability, including hydroelectric infrastructure renewal projects and AMI.

ENL

NSPML

Through its subsidiary, NSPML, ENL has invested $1.8 billion of equity, debt and working capital, including $209 million of AFUDC, in development of the Maritime Link Project. This investment consists of $554 million in equity, comprised of $452 million in equity contributed and $102 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The project debt has been guaranteed by the Government of Canada.

The Maritime Link entered service on January 15, 2018 and provides for the transmission of energy and improved reliability and ancillary benefits, supporting the efficiency and reliability of both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill project is complete, which is anticipated in the second half of 2020.

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 November 27, 2019, the UARB approved NSPML’s interim assessment for recovery from NSPI of 2020 Maritime Link costs of approximately $145 million (2019 - $111 million). The total recovery of $145 million includes approximately $115 million of operating and maintenance, debt financing and equity financing costs, and approximately $30 million for depreciation and amortization of financing costs. This payment is subject to a holdback of up to $10 million. Recovery of the $115 million of operating and maintenance, debt financing and equity financing costs began on January 1, 2020. Beginning June 1, 2020, recovery of the $30 million of depreciation and amortization of financing costs will be included in NSPI customer rates, with payment of this recovery to NSPML to begin on the earlier of the confirmation of delivery of the NS Block and November 1, 2020. NSPML expects to file a final cost assessment with the UARB in 2020.

In 2020, NSPML expects to invest approximately $20 million (2019 - $28 million) in capital.

LIL

ENL is a limited partner with Nalcor Energy in LIL, with total project costs currently estimated at $3.7 billion. Equity earnings are recorded based on an annual ROE of 8.5 per cent of the equity invested. The ROE is approved by the NLPUB.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera’s current equity investment is $579 million, comprised of $410 million in equity contribution and $169 million of accumulated equity earnings. Emera’s total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million after all Lower Churchill projects, including Muskrat Falls, are completed. Nalcor is forecasting these projects to be completed in the second half of 2020.

Cash earnings and return of equity are forecasted by Nalcor to begin in Q4 2020, and until that point Emera will continue to record AFUDC earnings.

Equity earnings from NSPML and LIL are expected to be higher in 2020, compared to 2019. Both the NSPML and LIL investments are recorded as “Investments subject to significant influence” on Emera’s Consolidated Balance Sheets.

Other Electric Utilities

Other Electric Utilities includes Emera Maine, a regulated transmission and distribution electric utility in the state of Maine, and Emera (Caribbean) Incorporated (“ECI”), a holding company with regulated electric utilities. ECI’s regulated utilities include BLPC, a vertically integrated regulated electric utility on the island of Barbados, GBPC, a vertically integrated regulated electric utility on Grand Bahama Island, and a 51.9 per cent interest in Domlec, a vertically integrated regulated electric utility on the island of Dominica. ECI also holds a 19.1 per cent interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia which is accounted for on the equity basis.

On March 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in early 2020, subject to MPUC approval. Refer to the “Developments” section for further details. As a result of the pending sale, Emera Maine’s assets and liabilities were classified as held for sale in Q1 2019.

Emera Maine

With approximately $1.3 billion USD of assets and approximately 159,000 customers, Emera Maine owns and operates approximately 2,000 kilometres of transmission facilities and 10,000 kilometres of distribution facilities. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine’s T&D networks.

Approximately 48 per cent of Emera Maine’s operating revenue represents distribution operations, 47 per cent is associated with transmission operations and 5 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

BLPC

With approximately $420 million USD of assets and approximately 131,000 customers, BLPC owns 266 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. The utility has an additional 12 MW of capacity from rental units. BLPC owns approximately 168 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC’s approved regulated return on rate base is 10.0 per cent.

GBPC

With approximately $300 million USD of assets and approximately 17,800 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. In January 2020, the GBPA approved GBPC’s regulated return on rate base of 8.34 per cent for 2020 (2019 - 8.44 per cent).

Domlec

Domlec serves approximately 31,000 customers. Domlec owns 27 MW of generating capacity of which 74 per cent is oil-fired and 26 per cent is hydro. Domlec owns approximately 471 kilometres of transmission facilities and 697 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

Other Electric Utilities Outlook

Other Electric Utilities' earnings are expected to increase over the prior year due to the GBPC impairment charge recognized in 2019 and higher earnings in 2020 from the Caribbean utilities, partially offset by lower earnings contribution from Emera Maine as a result of the expected sale in early 2020. For the Caribbean, GBPC's earnings are expected to increase as load continues to recover after Hurricane Dorian (discussed below), and earnings from both BLPC and Domlec are expected to be comparable to 2019.

On September 1, 2019, Hurricane Dorian struck Grand Bahama Island causing significant damage across the island. GBPC sustained damage to its generation, transmission and distribution assets. GBPC has restored power to all customers who have requested power and are able to receive it and as of December 31, 2019, power was restored to approximately 92 per cent of its customers. Post-hurricane load is down approximately 13 per cent. Management anticipates that demand will recover to pre-storm levels by the end of 2021. Refer to the "Developments" section for further details.

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 negotiating the terms of the new licenses under the amended legislation.

In 2020, capital expenditures in the Other Electric Utilities segment are expected to be approximately $130 million USD (including investment in Emera Maine for the first quarter only) (2019 – $150 million USD). ECI's utilities are forecasting capital investment in more efficient and cleaner sources of generation, including renewables and battery storage. In early February 2020, BLPC completed the installation of 15 MW of additional generation. BLPC expects to complete the installation of a 33MW diesel engine by mid-2020. This 33 MW plant is expected to increase efficiency and bridge BLPC's transition to increased renewable sources of generation. Emera Maine expects to invest primarily in transmission and distribution projects supporting normal system reliability.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure includes PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida; NMGC, a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico; SeaCoast, a regulated intrastate natural gas transmission company offering services in Florida; Brunswick Pipeline, a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern United States; and Emera's non-consolidated investment in M&NP.

Peoples Gas System

With approximately $1.6 billion USD of assets and approximately 406,000 customers, the PGS system includes approximately 21,730 kilometres of natural gas mains and 12,070 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2.1 billion therms in 2019.

The approved ROE range for PGS is 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. The bottom of the range will increase to 9.75 per cent in 2021, absent a rate case filing for that year. An ROE of 10.75 per cent is used for the calculation of return on investments for clauses.

New Mexico Gas Company, Inc.

With approximately $1.1 billion USD of assets and approximately 534,000 customers, NMGC serves approximately 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,488 kilometres of transmission lines and 17,223 kilometres of distribution lines. Annual natural gas throughput was approximately 969 million therms in 2019.

The approved ROE for NMGC is 9.1 per cent, on an allowed equity capital structure of 52 per cent. On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019. The new rates are being phased in over two years and are expected to result in an annual revenue increase of approximately $3 million USD. The NMPRC also approved the utility's weather adjustment mechanism.

Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure earnings are anticipated to be lower than 2019 due to decreased earnings from NMGC as a result of the recognition of tax reform benefits, and the approved change in treatment of NOL carryforwards in 2019.

Earnings from PGS are expected to be consistent with 2019. PGS expects customer growth rates in 2020 to be consistent with 2019, reflecting economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. Assuming normal weather in 2020, PGS sales volumes are expected to increase at a higher rate in 2020, as 2019 energy sales were impacted by unfavourable weather. Despite these expected revenue increases, significant capital investments and related growth in rate base is resulting in PGS anticipating it will earn below its allowed ROE range in 2020. Consistent with its FPSC-approved 2018 tax reform settlement agreement, PGS is permitted to initiate a general base rate proceeding during 2020, regardless of its earned ROE at the time, provided the new rates do not become effective before January 1, 2021. Therefore, as a result of forecasted revenue requirements being higher than what is in current rates, on February 7, 2020, PGS notified the FPSC that it is planning to file a base rate proceeding in April 2020 for new rates effective January 2021.

NMGC anticipates earning at or near its approved ROE in 2020 and expects rate base to be higher than 2020. Customer growth rates are expected to be consistent with 2019, reflecting expectations for housing starts and new connections. Assuming normal weather in 2020, NMGC sales volumes are expected to decrease, as 2019 energy sales benefited from favourable weather in the first half of the year.

On December 23, 2019, NMGC filed a future year base rate case with the NMPRC for new rates effective January 2021. The proposed new rates reflect the recovery of capital investment in pipelines and related infrastructure. The estimated annual incremental revenue requirement is approximately $13 million USD. A decision from the NMPRC is expected in late 2020.

In 2020, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $580 million USD (2019 - $331 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will complete the Santa Fe Mainline Looping project in 2020 and will continue to invest in system improvements.

In 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. (“Seminole”) to provide long-term firm gas transportation service to Seminole’s new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast is constructing and will operate a 21-mile, 30-inch pipeline lateral that is anticipated to go into service by 2022. The estimated capital investment is projected to be approximately $110 million USD, with $35 million USD invested through 2019 and $48 million USD expected to be invested in 2020. SeaCoast is also jointly developing the 26.5 mile, 16-inch Callahan Pipeline with Peninsula Pipeline Co., an affiliate of Florida Public Utilities. This pipeline is expected to go into service in 2021. SeaCoast will provide long-term firm gas transportation service to PGS in the northeast Florida area under a long-term transportation agreement between SeaCoast and PGS, which was approved by the FPSC in November 2019. SeaCoast’s portion of the estimated capital investment in the Callahan Pipeline is projected to be approximately $32 million USD, with $6 million USD invested through 2019 and approximately $26 million USD expected to be invested in 2020.

Other

The Other segment includes those business operations that in a normal year are below the required threshold for reporting as separate segments; and corporate expense and revenue items that are not directly allocated to the operations of Emera’s subsidiaries and investments.

Business operations in Other include Emera Energy, which consists of:

- Emera Energy Services (“EES”), a wholly owned physical energy marketing and trading business;
- Brooklyn Power Corporation (“Brooklyn Energy’), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
- an equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.

In 2019, the Company completed the sale of assets previously reported in this segment including the sale of its NEGG and Bayside facilities in March 2019 and the sale of its Emera Utility Services equipment and inventory in December 2019.

Corporate items included in the Other segment are certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings recorded in “Intercompany revenue” and interest expense on corporate debt in both Canada and the US. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera’s subsidiaries and investments.

Earnings from EES are generally dependent on market conditions. In particular, volatility in electricity and natural gas markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 generally providing the greatest opportunity for earnings. The business is generally expected to deliver annual adjusted net earnings of $15 to $30 million USD ($45 to $70 million USD of margin), with the opportunity for upside when market conditions present.

The Other segment is expected to contribute positively to earnings in 2020 due to the sale of Emera Maine, with a material gain expected to be recognized in earnings at closing. Absent this gain, the adjusted net loss from the Other segment is expected to decrease over the prior year, primarily due to lower corporate costs and expected EES contribution within its normal range in 2020, partially offset by the 2019 sale of NEGG. Corporate costs are expected to be lower due to decreased interest expense related to debt maturities and 2019 recognition of the corporate share of the unrecoverable loss related to the impact of Hurricane Dorian on GBPC.

In 2020, capital expenditures in the Other segment are expected to be approximately $74 million (2019 - $60 million), including investment in contracted energy infrastructure.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2018 and December 31, 2019 include:

millions of Canadian dollars	Total Increase (Decrease)	Classification of Emera Maine as Held for Sale (1)	Other Increase (Decrease)	Explanation of Other Increase (Decrease)
Assets				
Cash and cash equivalents	**$ (94)**	**$ -**	**$ (94)**	Decreased due to additions of property, plant and equipment and payment of common and preferred dividends. These were partially offset by cash from operations, proceeds from disposal of assets, changes in borrowings and the issuance of common shares.
Derivative instruments (current and long-term)	**(80)**	**-**	**(80)**	Decreased due to settlement of derivatives and lower commodity prices at NSPI.
Regulatory assets (current and long-term)	**(17)**	**(138)**	**121**	Increased due to deferred income tax regulatory asset and deferrals related to derivative instruments at NSPI, partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Receivables and other assets (current and long-term)	**(125)**	**(78)**	**(47)**	No significant change after removing impact of held for sale classification.
Assets held for sale (current and long-term), net of liabilities	**(117)**	**691**	**(808)**	Decreased due to completion of the sale of the NEGG facilities.
Property, plant and equipment, net of accumulated depreciation and amortization	**(545)**	**(1,293)**	**748**	Increased due to additions at Tampa Electric, PGS, NMGC and NSPI partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Goodwill	**(478)**	**(148)**	**(330)**	Decreased due to the effect of a stronger CAD on the translation of Emera’s foreign subsidiaries and the GBPC impairment charge.

Liabilities and Equity				
Short-term and long-term debt (including current portion)	**(880)**	**(516)**	**(364)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and repayment of Emera US Finance LP USD note upon maturity, partially offset by proceeds from Emera's non-revolving credit facility, and issuances at Tampa Electric, NSPI and Emera Maine.
Accounts payable	**(171)**	**(35)**	**(136)**	Decreased due to lower commodity prices at Emera Energy, lower cash collateral positions at NSPI and Emera Energy, and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Deferred income tax liabilities, net of deferred income tax assets	**(46)**	**(204)**	**158**	Increased primarily due to tax deductions in excess of accounting depreciation related to property, plant, and equipment.
Regulatory liabilities (current and long-term)	**(429)**	**(156)**	**(273)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and deferrals related to derivative instruments, fuel adjustment mechanism and cost of removal at NSPI.
Pension and post-retirement liabilities	**(181)**	**(73)**	**(108)**	Decreased due to higher returns and the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Common stock	**400**	**-**	**400**	Increased due to the dividend reinvestment plan, increase in options exercised and shares issued under Emera's at-the-market equity program ("ATM Program").
Accumulated other comprehensive income	**(243)**	**-**	**(243)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Retained earnings	**98**	**-**	**98**	Increased due to net income in excess of dividends paid.

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to the "Developments" section and note 4 in the consolidated financial statements for further details.

DEVELOPMENTS

Hurricane Dorian

In September 2019, Hurricane Dorian impacted GBPC, NSPI and Tampa Electric, as discussed below.

GBPC - On September 1, 2019, Dorian struck Grand Bahama 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. All 19,300 of GBPC's customers lost power following the storm. As of December 31, 2019, power was restored to all customers who were able to receive power, or approximately 17,800 customers.

Earnings Impact:

Emera's 2019 earnings decreased by approximately $62 million as a result of the impact of the hurricane, reflecting an impairment charge of $34 million, including $30 million related to goodwill, $13 million related to loss of load and $15 million for the corporate share of the unrecoverable loss on GBPC's facilities. Refer to "Significant Items Affecting Earnings" for further details.

Balance Sheet Impact:

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are self-insured. It is currently estimated that restoration costs for GBPC self-insured assets will be approximately $15 million USD. In January 2020, the GBPA approved the recovery of these costs through rates over a five-year period. Approximately $12 million USD of these estimated costs were incurred in 2019, and recorded as a regulatory asset.

As a result of the damage caused by Hurricane Dorian, the Company completed an asset impairment analysis in Q4 2019. Property, plant and equipment and inventory with a book value of approximately $18 million USD was determined to be impaired and was reclassified as a regulatory asset. GBPC recorded an offsetting insurance receivable of $15 million USD against this regulatory asset. It is anticipated that the regulatory asset balance of $3 million USD remaining at December 31, 2019 will also be recovered through insurance.

NSPI - On September 7, 2019, Dorian struck Nova Scotia with sustained hurricane force winds of over 100 kilometres per hour and peak gusts of approximately 155 kilometres per hour. The storm caused widespread damage to NSPI's transmission and distribution system and, at the height of the storm, approximately 412,000 customers were affected. By September 10, 2019, power had been restored to 80 per cent of those affected, and all customers were restored by September 17, 2019. NSPI incurred $40 million of storm restoration costs of which $24 million was capitalized to property, plant and equipment, with the remaining $16 million charged to OM&G expense. There was no overall impact on NSPI earnings as NSPI's increased storm costs were offset by some of the excess non-fuel revenues that were recorded in 2019.

Tampa Electric – In preparation for Hurricane Dorian, Tampa Electric incurred approximately $8 million USD in storm costs. There was no impact to Tampa Electric earnings as these costs were charged to Tampa Electric's storm reserve regulatory liability. As of December 31, 2019, the storm reserve regulatory liability balance was $62 million ($48 million USD).

At-The-Market Equity Program

On July 11, 2019, Emera established an ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was established under a prospectus supplement to the Company's short-form base shelf prospectus which expires on July 14, 2021. During 2019, approximately 1.8 million common shares were issued under the ATM Program at an average price of $56.56 per share for gross proceeds of $100 million ($98.7 million net of issuance costs). As at December 31, 2019, an aggregate gross sales limit of $500 million remains available for issuance under the ATM program.

Increase in Common Dividend

On September 27, 2019, Emera's Board of Directors approved an increase in the annual common share dividend rate to $2.45 from $2.35. The first payment was effective November 15, 2019. Emera extended its four to five per cent annual dividend growth rate target through to 2022.

Removal of Legislative Restriction on Non-Canadian Resident Ownership of Emera Shares

On April 12, 2019, amendments to the *Nova Scotia Power Privatization Act* and the *Nova Scotia Power Reorganization (1998) Act* were enacted, removing the legislative restriction preventing non-Canadian residents from holding more than 25 per cent of Emera voting shares, in aggregate. On July 11, 2019, shareholders passed a special resolution to immediately amend the Company's articles of association to remove this restriction.

Sale of Emera Energy's New England Gas and Bayside Generating Facilities

On March 29, 2019, Emera completed the sale of its three NEGG facilities for cash proceeds of $799 million ($598 million USD), including working capital adjustments. On March 5, 2019, the Company sold its Bayside facility for cash proceeds of $46 million. An immaterial loss was recognized on these dispositions. Proceeds from the sales were used to reduce corporate debt and support capital investment opportunities within Emera's regulated utilities.

Pending Sale of Emera Maine

On March 25, 2019, Emera announced the sale of Emera Maine for a total enterprise value of approximately $1.3 billion USD including cash proceeds of $959 million USD, transferred debt and a working capital adjustment on close. The transaction is expected to close in early 2020, subject to the approval of the MPUC. All other required regulatory approvals have been received.

A material gain on the sale is expected to be recognized in earnings at closing. Proceeds from the sale will be used to support capital investment opportunities within Emera's regulated utilities and to reduce corporate debt.

Appointments

Executive

Effective October 21, 2019, Karen Hutt was appointed Executive Vice President, Strategy & Business Development for Emera. Most recently, Ms. Hutt was President and CEO of NSPI.

Effective October 21, 2019, Wayne O'Connor was appointed President and CEO of NSPI. Most recently, Mr. O'Connor was Executive Vice President, Strategy & Business Development for Emera.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
Balance, December 31, 2017	228.77	$ 5,601
Conversion of Convertible Debentures	0.01	-
Issuance of common stock	0.45	22
Issued for cash under Purchase Plans at market rate	4.87	200
Discount on shares purchased under Dividend Reinvestment Plan	-	(9)
Options exercised under senior management stock option plan	0.02	1
Employee Share Purchase Plan	-	1
Balance, December 31, 2018	234.12	$ 5,816
Conversion of Convertible Debentures	0.03	1
Issuance of common stock (1)	1.77	99
Issued for cash under Purchase Plans at market rate	3.99	202
Discount on shares purchased under Dividend Reinvestment Plan	-	(7)
Options exercised under senior management stock option plan	2.57	104
Employee Share Purchase Plan	-	1
Balance, December 31, 2019	**242.48**	**$ 6,216**

(1) As at December 31, 2019, a total of 1.77 million common shares have been issued through Emera's ATM Program at an average price of $56.56 per share for gross proceeds of $100 million ($98.7 million net of issuance costs).

As at February 11, 2020, the amount of issued and outstanding common shares was 242.6 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2019 was 242.9 million (2018 – 234.9 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2019 was 239.9 million (2018 – 233.0 million).

FINANCIAL HIGHLIGHTS

Florida Electric Utility

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 473**	$ 501	**$ 1,965**	$ 2,066
Regulated fuel for generation and purchased power	**143**	155	**582**	637
Contribution to consolidated net income	**$ 61**	$ 64	**$ 316**	$ 294
Contribution to consolidated net income – CAD	**$ 80**	$ 83	**$ 419**	$ 381
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.33**	$ 0.35	**$ 1.75**	$ 1.64
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.32**	$ 1.30	**$ 1.33**	$ 1.30
EBITDA	**$ 187**	$ 184	**$ 828**	$ 774
EBITDA – CAD	**$ 245**	$ 241	**$ 1,098**	$ 1,003

Net Income

Highlights of the net income changes are summarized in the following table:

For the millions of US dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2018	**$**	**64**	**$**	**294**
Decreased operating revenues - see Operating Revenues - Regulated Electric below		(28)		(101)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		12		55
Decreased OM&G expenses due to Tampa Electric's regulatory agreement to net 2018 tax reform benefits with storm costs that were recorded through OM&G in 2018. Beginning in 2019, tax reform benefits are reflected in lower base rates		19		96
Increased depreciation and amortization due to increased property, plant and equipment		(6)		(24)
Increased interest expense in support of increased capital spending		(3)		(15)
Decreased income tax expense quarter-over-quarter primarily due to a reduction in the Florida state corporate income tax rate. Decreased income tax expense year-over-year primarily due to a reduction in the Florida state corporate income tax rate and higher investment tax credits related to solar projects		3		7
Other		-		4
Contribution to consolidated net income – 2019	**$**	**61**	**$**	**316**

Florida Electric Utility's CAD contribution to consolidated net income decreased $3 million in Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, Florida Electric Utility's CAD contribution to consolidated net income increased $38 million in 2019. Tampa Electric's contribution decreased in Q4 2019 due to unfavourable weather. Year-over-year earnings increased due to higher contribution from solar and customer growth. These increases were partially offset by higher depreciation expense and higher interest expense as the result of higher capital investments. The reduction in base rates due to tax reform was offset by lower OM&G expense in 2019, as the 2018 tax reform benefits were netted against the storm costs recorded through OM&G expense in 2018.

The impact of the change in the foreign exchange rate increased CAD earnings for the quarter and year ended December 31, 2019 by $1 million and $9 million, respectively.

Operating Revenues – Regulated Electric

Beginning January 1, 2019, as approved by the FPSC, base rates at Tampa Electric were lowered to reflect the impact of tax reform, resulting in a $29 million decrease in revenue in Q4 2019, and approximately $103 million decrease for the year ended December 31, 2019.

Electric revenues decreased $28 million to $473 million in Q4 2019, compared to $501 million in Q4 2018. For the year ended December 31, 2019, electric revenues decreased $101 million to $1,965 million in 2019, from $2,066 million in 2018. The decreases in both periods were due to lower clause revenues and lower base rates as a result of US tax reform, partially offset by higher base revenues related to in-service of solar generation projects, and customer growth.

Electric revenues and sales volumes are summarized in the following tables by customer class:

Q4 Electric Revenues
millions of US dollars

		2019		2018
Residential	**$**	**254**	$	265
Commercial		**141**		147
Industrial		**39**		40
Other (1)		**39**		49
Total	**$**	**473**	$	501

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

Annual Electric
millions of US dollars

		2019		2018
Residential	**$**	**1,046**	$	1,067
Commercial		**562**		582
Industrial		**156**		161
Other (1)		**201**		256
Total	**$**	**1,965**	$	2,066

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

Q4 Electric Sales Volumes
Gigawatt hours ("GWh")

	2019	2018
Residential	**2,303**	2,320
Commercial	**1,536**	1,568
Industrial	**501**	490
Other	**579**	514
Total	**4,919**	4,892

Annual Electric Sales Volumes
GWh

	2019	2018
Residential	**9,584**	9,418
Commercial	**6,240**	6,266
Industrial	**2,021**	2,014
Other	**2,094**	2,219
Total	**19,939**	19,917

Regulated Fuel for Generation and Purchased Power

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is 5,641 MW. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Regulated fuel for generation and purchased power decreased $12 million to $143 million in Q4 2019, compared to $155 million in Q4 2018. For the year ended December 31, 2019, regulated fuel for generation and purchased power decreased $55 million to $582 million in 2019, compared to $637 million in 2018. The decrease in both periods was due to increased use of lower-cost natural gas and increased solar generation.

Q4 Production Volumes
GWh

	2019	2018
Natural gas	**4,075**	4,160
Coal	**323**	430
Oil and petcoke	**-**	-
Solar	**169**	68
Purchased power	**210**	495
Total	**4,777**	5,153

Annual Production Volumes
GWh

	2019	2018
Natural gas	**17,514**	16,097
Coal	**1,214**	3,088
Oil and petcoke	**-**	472
Solar	**756**	118
Purchased power	**1,290**	1,222
Total	**20,774**	20,997

Q4 Average Fuel Costs

US dollars		**2019**		2018
Dollars per Megawatt hour ("MWh")	**$**	**30**	$	30

Annual Average Fuel

US dollars		**2019**		2018
Dollars per MWh	**$**	**28**	$	30

Tampa Electric's fuel costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first (renewable energy from solar), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

Average fuel cost per MWh for the quarter was consistent compared to Q4 2018. Average fuel cost per MWh decreased for the year ended December 31, 2019, compared to 2018, due to increased use of lower-cost natural gas and lower-cost solar generation.

Regulatory Recovery Mechanisms

Tampa Electric is regulated by the FPSC. Tampa Electric is also subject to regulation by the 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. Base rates are determined in FPSC rate setting hearings which occur at the initiative of Tampa Electric, the FPSC or other interested parties.

Other Cost Recovery

Fuel Recovery Clause
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. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Other Cost Recovery Clauses
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 clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred to a corresponding regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Storm Reserve
The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. Tampa Electric 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.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 364**	$ 385	**$ 1,430**	$ 1,440
Regulated fuel for generation and purchased power (1)	**183**	179	**663**	639
Income from equity investments	**23**	16	**91**	87
Contribution to consolidated net income	**$ 58**	$ 44	**$ 229**	$ 218
Contribution to consolidated earnings per common share – basic	**$ 0.24**	$ 0.19	**$ 0.95**	$ 0.94
EBITDA	**$ 151**	$ 140	**$ 592**	$ 584

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Consolidated Statements of Income, however it is excluded in the segment overview.

Canadian Electric Utilities' contribution is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
NSPI	**$ 35**	$ 28	**$ 138**	$ 131
Equity investment in NSPML	**11**	5	**46**	45
Equity investment in LIL	**12**	11	**45**	42
Contribution to consolidated net income	**$ 58**	$ 44	**$ 229**	$ 218

Net Income

Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2018	**$ 44**	**$ 218**
Decreased operating revenues - see Operating Revenues – Regulated Electric below	(21)	(10)
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(4)	(24)
Decreased FAM and fixed cost deferrals due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment in both periods	22	44
Increased OM&G expenses year-over-year primarily due to higher costs for vegetation management, storm costs, variable compensation, lower administrative overhead allocated to property, plant and equipment and increased costs for information technology	1	(27)
Increased depreciation and amortization due to increased property, plant and equipment	(4)	(12)
Increase in income from equity investments – refer to Income from Equity Investments in NSPML and LIL below	7	4
Decreased other expenses, net primarily due to lower pension costs	5	21
Decreased income taxes primarily due to changes in tax legislation, prior year change in tax reserve, tax benefits of capital investment related to Post-Tropical Storm Dorian and decreased non-deductible pension expense partially offset by decreased tax deductions in excess of accounting depreciation related to property, plant and equipment	5	18
Other	3	(3)
Contribution to consolidated net income – 2019	**$ 58**	**$ 229**

Canadian Electric Utilities’ contribution to consolidated net income increased $14 million to $58 million in Q4 2019, compared to $44 million for the same period in 2018. This increase was a result of increased income from equity investments, decreased income taxes and lower pension costs.

For the year ended December 31, 2019 Canadian Electric Utilities’ contribution to consolidated net income increased $11 million to $229 million compared to $218 million in 2018. This increase was a result of lower pension costs, decreased income taxes, higher non-fuel revenues and increased income from equity investments. This was partially offset by increased OM&G expenses and depreciation.

On September 7, 2019, Hurricane Dorian struck Nova Scotia. NSPI incurred $40 million of storm restoration costs, of which $24 million was capitalized to property, plant and equipment with the remaining $16 million charged to OM&G. There was no overall impact on NSPI earnings as NSPI’s increased storm costs were offset by some of the excess non-fuel revenues that were recorded in 2019.

The timing of regulatory deferrals causes quarterly earnings volatility, while full year results are more predictable.

NSPI

Operating Revenues – Regulated Electric

Operating revenues decreased $21 million to $364 million in Q4 2019, compared to $385 million in Q4 2018 primarily due to decreased industrial and commercial class sales volume and decreased volume due to weather, partially offset by increased fuel related electricity pricing in 2019. For the year ended December 31, 2019, operating revenues decreased $10 million to $1,430 million compared to $1,440 million in 2018 primarily due to decreased industrial and commercial class sales volume and the impact of the Maritime Link assessment. This was partially offset by increased fuel-related electricity pricing in 2019, increased sales volume due to weather and increased residential class sales volume.

Electric revenues and sales volumes are summarized in the following tables by customer class:

Q4 Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**194**	$	199
Commercial		**102**		107
Industrial		**50**		62
Other		**10**		10
Total	**$**	**356**	$	378

Annual Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**746**	$	731
Commercial		**400**		405
Industrial		**210**		233
Other		**45**		43
Total	**$**	**1,401**	$	1,412

Q4 Electric Sales Volumes
GWh

	2019	2018
Residential	**1,210**	1,259
Commercial	**763**	799
Industrial	**571**	669
Other	**78**	76
Total	**2,622**	2,803

Annual Electric Sales Volumes
GWh

	2019	2018
Residential	**4,664**	4,581
Commercial	**3,068**	3,102
Industrial	**2,388**	2,611
Other	**350**	323
Total	**10,470**	10,617

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $4 million to $183 million in Q4 2019, compared to $179 million in Q4 2018. For the year ended December 31, 2019 regulated fuel for generation and purchased power increased $24 million to $663 million compared to $639 million 2018. Changes in both periods were primarily due to increased commodity pricing and the payment of the Maritime Link assessment.

Q4 Production Volumes
GWh

	2019	2018
Coal	**1,398**	1,466
Natural gas	**322**	275
Oil and petcoke	**149**	254
Purchased power – other	**139**	175
Total non-renewables	**2,008**	2,170
Wind and hydro	**306**	318
Purchased power – Independent Power Producers ("IPP")	**371**	369
Purchased power – Community Feed-in Tariff program ("COMFIT")	**163**	153
Biomass	**14**	60
Total renewables	**854**	900
Total production volumes	**2,862**	3,070

Annual Production Volumes
GWh

	2019	2018
Coal	**4,949**	4,930
Natural gas	**1,369**	1,427
Oil and petcoke	**981**	1,246
Purchased power – other	**786**	540
Total non-renewables	**8,085**	8,143
Wind and hydro	**1,289**	1,202
Purchased power – IPP	**1,202**	1,275
Purchased power – COMFIT	**552**	553
Biomass	**73**	189
Total renewables	**3,116**	3,219
Total production volumes	**11,201**	11,362

Q4 Average Fuel Costs

	2019	2018
Dollars per MWh	**$ 64**	$ 58

Annual Average Fuel Costs

	2019	2018
Dollars per MWh	**$ 59**	$ 56

Average fuel cost per MWh increased in Q4 2019 and for the year ended December 31, 2019, compared to the same periods in 2018, primarily due to increased commodity pricing, timing of the payments of the Maritime Link assessment and generation mix.

NSPI's FAM regulatory liability balance decreased $46 million from $161 million at December 31, 2018 to $115 million at December 31, 2019, primarily due to under-recovery of current period fuel costs and a refund to customers of the 2018 Maritime Link assessment. This was partially offset by the recovery of the Maritime Link assessment in 2019 to be returned to customers as part of the assessment decision, demand side management costs to be returned to customers in subsequent years and interest on the FAM balance.

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place.

NSPI-owned hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, followed by natural gas. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each. Generation mix may also be affected by plant outages, availability of renewable generation, plant performance and compliance with environmental standards and regulations.

The generation mix has transformed with the addition of new non-dispatchable renewable energy sources such as wind, including IPP and COMFIT, which typically have a higher cost per MWh than NSPI-owned generation or other purchased power sources.

ENL

Income from Equity Investments in NSPML and LIL

Income from equity investments increased $7 million to $23 million in Q4 2019 compared to the same period in 2018. Income from equity investments increased $4 million to $91 million for the year ended December 31, 2019 compared to 2018. Increased income from NSPML in both periods was due to timing of revenue and operational costs and increased income from LIL, due to higher equity investment. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI.

Regulatory Recovery Mechanisms

NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia (the "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 subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request.

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 an appropriate return to investors.

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel costs from customers through fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability.

On December 6, 2019, the UARB approved NSPI's three-year fuel stability plan which will result in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. For the years 2020 to 2022, differences between actual fuel costs and fuel revenues recovered from customers will be recovered from or returned to customers after 2022.

In December 2015, the *Electricity Plan Implementation (2015) Act ("Electricity Plan Act")* was enacted by the Province of Nova Scotia with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. NSPI operated under a Rate Stability Plan for fuel costs for 2017 through 2019 which included an average overall annual rate increase of 1.5 per cent to recover fuel costs for each of these three years.

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

On March 25, 2019, Emera announced the sale of Emera Maine. The transaction is expected to close in early 2020, subject to MPUC approval. The Company will continue to record depreciation on these assets, through the transaction closing date, as the depreciation continues to be reflected in customer rates, and will be reflected in the carryover basis of the assets when sold. Refer to the "Developments" section for further details.

For the millions of US dollars (except per share amounts)		Three months ended December 31 2019		2018		Year ended December 31 2019		2018
Operating revenues – regulated electric	**$**	**140**	$	140	**$**	**561**	$	574
Regulated fuel for generation and purchased power (1)		**58**		55		**216**		225
Adjusted contribution to consolidated net income	**$**	**10**	$	20	**$**	**57**	$	69
Adjusted contribution to consolidated net income – CAD	**$**	**14**	$	25	**$**	**76**	$	89
GBPC impairment charge		**(26)**		-		**(26)**		-
After-tax equity securities mark-to-market gain (loss)		**-**		(2)		**2**		(3)
Contribution to consolidated net income	**$**	**(16)**	$	18	**$**	**33**	$	66
Contribution to consolidated net income – CAD	**$**	**(19)**	$	23	**$**	**45**	$	85
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$**	**0.06**	$	0.11	**$**	**0.32**	$	0.38
Contribution to consolidated earnings per common share – basic – CAD	**$**	**(0.08)**	$	0.10	**$**	**0.19**	$	0.36
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.32**	$	1.32	**$**	**1.33**	$	1.30
Adjusted EBITDA	**$**	**38**	$	47	**$**	**187**	$	200
Adjusted EBITDA – CAD	**$**	**52**	$	63	**$**	**249**	$	260

(1) Regulated fuel for generation and purchased power includes transmission pool expense.

GBPC Impairment Charge

As a result of the damage caused by Hurricane Dorian, the Company completed an asset and goodwill impairment analysis in Q4 2019 and recognized a non-cash impairment charge of $26 million USD 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. Refer to the "Developments" section and note 21 to the consolidated financial statements for the year ended December 31, 2019 for further details.

Other Electric Utilities' adjusted contribution is summarized in the following table:

For the millions of US dollars		Three months ended December 31 2019		2018		Year ended December 31 2019		2018
Emera Maine	**$**	**7**	$	9	**$**	**35**	$	34
ECI		**3**		11		**22**		35
Adjusted contribution to consolidated net income	**$**	**10**	$	20	**$**	**57**	$	69

Net Income

Highlights of the net income changes are summarized in the following table:

For the millions of US dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2018	**$**	**18**	**$**	**66**
Operating revenues - see Operating Revenues - Regulated Electric below (1)		5		(2)
Regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below (1)		(5)		4
Decreased earnings at GBPC due to Hurricane Dorian		(5)		(11)
GBPC impairment charge		(26)		(26)
Other (1)		(3)		2
Contribution to consolidated net income – 2019	**$**	**(16)**	**$**	**33**

(1) Excludes the impact of Hurricane Dorian at GBPC

Excluding the change in mark-to-market and the GBPC impairment charge, Other Electric Utilities CAD's contribution to consolidated net income decreased $11 million in Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, the CAD contribution decreased $13 million compared to 2018. ECI's contribution decreased in both periods mainly due to lower earnings in GBPC as a result of the impact of Hurricane Dorian in Q3 2019. For the year ended December 31, 2019 compared to 2018, this was partially offset by higher sales volumes at Domlec due to the completion of hurricane restoration in 2018. Emera Maine's contribution decreased in Q4 2019 due to an unfavourable transmission revenue adjustment. Emera Maine's contribution increased for the year ended December 31, 2019 compared to 2018 due to increased capitalized construction overheads.

The foreign exchange rate had minimal impact for the three months ended December 31, 2019 and increased adjusted CAD earnings by $2 million for the year ended December 31, 2019.

Operating Revenues – Regulated Electric

Operating revenues were consistent in Q4 2019 compared to Q4 2018. Lower sales at GBPC as a result of the impact of Hurricane Dorian were offset by increased sales volumes at Domlec and increased fuel revenue at ECI due to higher oil prices. For the year ended December 31, 2019, revenues decreased $13 million to $561 million compared to $574 million in 2018 due to lower sales at GBPC as a result of the impact of Hurricane Dorian and at Emera Maine there were lower stranded cost rates, unfavourable transmission revenue adjustments and lower transmission pool revenue as a result of lower rates.

Electric revenues and sales volumes are summarized in the following tables by customer class:

Q4 Electric Revenues
millions of USD

		2019		2018
Residential	**$**	**54**	$	52
Commercial		**63**		68
Industrial		**8**		9
Other (1)		**15**		11
Total	**$**	**140**	$	140

(1) Other revenue includes amounts recognized relating to Emera Maine's FERC transmission rate refunds and other transmission revenue adjustments.

Annual Electric Revenues
millions of USD

		2019		2018
Residential	**$**	**207**	$	202
Commercial		**256**		270
Industrial		**33**		35
Other (1)		**65**		67
Total	**$**	**561**	$	574

(1) Other revenue includes amounts recognized relating to Emera Maine's FERC transmission rate refunds and other transmission revenue adjustments.

Q4 Electric Sales Volumes

GWh	**2019**	2018
Residential	**329**	331
Commercial	**376**	378
Industrial	**120**	110
Other	**7**	7
Total	**832**	826

Annual Electric Sales Volumes

GWh	**2019**	2018
Residential	**1,280**	1,273
Commercial	**1,492**	1,517
Industrial	**464**	438
Other	**26**	27
Total	**3,262**	3,255

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $3 million to $58 million in Q4 2019, compared to $55 million in Q4 2018 due to higher oil prices at ECI, partially offset by lower generation at GBPC as a result of Hurricane Dorian. For the year ended December 31, 2019, regulated fuel for generation and purchased power decreased $9 million to $216 million compared to $225 million in 2018 due to lower generation at GBPC as a result of Hurricane Dorian and the expiration of a major purchased power contract at Emera Maine, partially offset by increased volumes at Domlec.

Q4 Production Volumes

GWh

	2019	2018
Oil	**332**	335
Hydro	**6**	7
Solar	**4**	5
Purchased power	**9**	7
Total	**351**	354

Annual Production Volumes

GWh

	2019	2018
Oil	**1,338**	1,330
Hydro	**20**	24
Solar	**19**	18
Purchased power	**34**	26
Total	**1,411**	1,398

Q4 Average Fuel Costs

US dollars	2019	2018
Dollars per MWh	**$ 135**	$ 127

(1) Production volumes and average fuel costs relate to ECI only.

Annual Average Fuel Costs

US dollars	2019	2018
Dollars per MWh	**$ 125**	$ 131

Average fuel cost per MWh increased in Q4 2019 compared to Q4 2018 due to higher oil prices at ECI and decreased for the year ended December 31, 2019 compared to 2018 due to lower average oil prices at ECI.

Regulatory Recovery Mechanisms

Emera Maine

Emera Maine’s distribution operations and stranded cost recoveries are regulated by the MPUC. The transmission operations are regulated by the FERC. Rates for these three elements are established in distinct regulatory proceedings.

Emera Maine’s distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. For stranded cost recoveries, Emera Maine is permitted to recover all prudently incurred stranded costs resulting from the industry restructuring in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Emera Maine’s transmission businesses operate based on formulas utilizing prior year actual transmission investments and operating costs. Emera Maine collects revenue for its bulk transmission assets from ISO New England. Emera Maine is also required to contribute toward the total cost of ISO New England pool transmission facilities on a ratable basis according to the proportion of total New England load that its customers represent.

BLPC

BLPC is regulated by the Fair Trading Commission, an independent regulator. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The FTC approves the calculation of the fuel charge, which is adjusted on a monthly basis.

GBPC

GBPC is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner.

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are self-insured. It is currently estimated that Hurricane Dorian restoration costs for GBPC self- insured assets will be approximately $15 million USD. In January 2020, the GBPA approved the recovery of these costs through rates over a five-year period. Approximately $12 million USD of these estimated costs were incurred in 2019, and recorded as a regulatory asset.

As a result of Hurricane Matthew in 2016, a regulatory asset was established to recover associated restoration costs. In addition, 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. This is achievable as the company's fuel costs over this period are forecasted to decrease. Fuel costs are managed through a fuel hedging program which allows predictability of these costs. Any over-recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory asset, until such time as the asset is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory asset, the excess will be placed in a new storm reserve. If the Hurricane Matthew deferral is not fully recovered at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

As a component of its regulatory agreement, GBPC has an Earnings Share Mechanism to allow for earnings on rate base to be deferred to a regulatory asset or liability at the rate of 50 per cent of amounts below a 7.44 per cent return on rate base and 50 per cent of amounts above 9.44 per cent return on rate base respectively.

Domlec

Domlec is regulated by the Independent Regulatory Commission, Dominica. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. Substantially all of Domlec fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover prudently incurred fuel costs from customers in a timely manner.

Gas Utilities and Infrastructure

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)		Three months ended December 31				Year ended December 31	
		2019		2018		**2019**		2018
Operating revenues – regulated gas (1)	**$**	**228**	$	233	**$**	**832**	$	835
Operating revenues – non-regulated		**3**		3		**12**		13
Total operating revenue	**$**	**231**	$	236	**$**	**844**	$	848
Regulated cost of natural gas		**76**		91		**264**		300
Income from equity investments		**3**		4		**17**		17
Adjusted contribution to consolidated net income		**37**		35		**139**		107
Adjusted contribution to consolidated net income – CAD		**51**		43		**183**		136
After-tax derivative mark-to-market gain		**-**		(1)		**-**		(1)
Contribution to consolidated net income	**$**	**37**	$	34	**$**	**139**	$	106
Contribution to consolidated net income – CAD	**$**	**51**	$	42	**$**	**183**	$	135
Adjusted contribution to consolidated earnings per common share – basic - CAD		**0.21**		0.18		**0.76**		0.58
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.21**	$	0.18	**$**	**0.76**	$	0.58
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.32**	$	1.31	**$**	**1.33**	$	1.29
Adjusted EBITDA	**$**	**84**	$	81	**$**	**311**	$	295
Adjusted EBITDA – CAD	**$**	**114**	$	107	**$**	**413**	$	381

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2018 - $13 million) for the three months ended December 31, 2019 and $45 million (2018 - $44 million) for the year ended December 31, 2019, however, it is excluded from the gas revenues analysis below.

Gas Utilities and Infrastructure's adjusted contribution is summarized in the following table:

For the millions of US dollars		Three months ended December 31				Year ended December 31		
		2019		2018		**2019**		2018
PGS	**$**	**12**	$	11	**$**	**54**	$	47
NMGC		**15**		10		**46**		20
Other		**10**		14		**39**		40
Contribution to adjusted consolidated net income	**$**	**37**	$	35	**$**	**139**	$	107

Net Income

Highlights of the net income changes are summarized in the following table:

For the millions of US dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2018	**$**	**34**	**$**	**106**
Decreased gas operating revenues net of recognition of tax reform benefits - see Operating Revenues - Regulated Gas below		(11)		(13)
Decreased cost of natural gas sold - see Regulated Cost of Natural Gas below		15		36
Increased OM&G expenses quarter-over-quarter due to higher operating cost at PGS. Year-over-year, OM&G expense also increased due to higher self-insurance and benefits expense in PGS and NMGC in 2019		(5)		(13)
Decreased depreciation and amortization due to accelerated amortization of assets related to MGP environmental remediation costs in 2018 at PGS and reduced PGS depreciation rates in 2019 related to the settlement agreement to net amortization of the MGP environmental regulatory asset and 2018 tax reform benefits		3		17
Recognition of tax benefit related to change in treatment of NOL carryforwards at NMGC		-		5
Recognition of tax reform benefits, net of tax, from January 2018 through June 2019 in NMGC, of which $6 million relates to 2018		6		9
Other		(5)		(8)
Contribution to consolidated net income – 2019	**$**	**37**	**$**	**139**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $9 million compared to Q4 2018. For the year ended December 31, 2019, Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $48 million compared to 2018. Increases in both periods were due to favourable weather in New Mexico, customer growth at PGS and lower depreciation and amortization at PGS. The year-over-year increase was also due to NMGC's recognition of $19 million ($14 million USD) of tax benefits in 2019.

The foreign exchange rate had minimal impact for the three months ended December 31, 2019 and increased CAD earnings by $4 million for the year ended 2019.

Operating Revenues – Regulated Gas

Beginning January 1, 2019, as approved by the FPSC, base rates at PGS were lowered to reflect the impact of tax reform, resulting in a $4 million USD decrease in revenue in Q4 2019 and a $12 million decrease for the year ended December 31, 2019.

Gas Utilities and Infrastructure's operating revenues decreased $5 million to $228 million in Q4 2019, compared to $233 million in Q4 2018. The decrease was the result of lower off-system sales at PGS, lower base rates at PGS reflecting the impact of tax reform and lower clause revenues in New Mexico, partially offset by customer growth in PGS.

For the year ended December 31, 2019, operating revenues decreased $3 million to $832 million, compared to $835 million in 2018. The decrease was the result of lower off-system sales and lower base rates at PGS reflecting the impact of tax reform, and lower clause-related revenue at PGS and New Mexico due to lower cost of natural gas sold partially offset by favourable weather in New Mexico, customer growth in PGS, and the NMPRC's approval of NMGC retaining tax reform benefits from January 1, 2018 to June 30, 2019.

Gas revenues and sales volumes are summarized in the following tables by customer class:

Q4 Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**109**	$	116
Commercial		**63**		60
Industrial (1)		**9**		9
Other (2)		**36**		35
Total (3)	**$**	**217**	$	220

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $11 million of finance income from Brunswick Pipeline (2018 – $13 million).

Annual Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**379**	$	381
Commercial		**225**		225
Industrial (1)		**37**		37
Other (2)		**146**		148
Total (3)	**$**	**787**	$	791

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $45 million of finance income from Brunswick Pipeline (2018 – $44 million).

Q4 Gas Volumes
Therms (millions)

	2019	2018
Residential	**138**	141
Commercial	**225**	214
Industrial	**376**	339
Other	**88**	72
Total	**827**	766

Annual Gas Volumes
Therms (millions)

	2019	2018
Residential	**413**	389
Commercial	**830**	795
Industrial	**1,482**	1,338
Other	**317**	269
Total	**3,042**	2,791

Regulated Cost of Natural Gas

PGS and NMGC purchase gas from various suppliers depending on the needs of their customers. In Florida, gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has firm transportation capacity for delivery by PGS to its customers. NMGC's natural gas is transported on major interstate pipelines and NMGC's intrastate transmission system to customers.

In Florida, natural gas service is unbundled for non-residential customers and residential customers who use more than 1,999 therms annually and elect the option. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. Because the commodity portion of bundled sales is included in operating revenues, at the cost of the gas on a pass-through basis, there is no net earnings effect when a customer shifts to transportation-only sales.

Regulated cost of natural gas decreased $15 million to $76 million in Q4 2019, compared to $91 million in Q4 2018. For the year ended December 31, 2019, regulated cost of natural gas decreased $36 million to $264 million in Q4 2019, compared to $300 million in 2018. The decrease in both periods was due to lower commodity costs in PGS and New Mexico and lower PGS off-system sales volume.

Gas sales by type are summarized in the following table:

Q4 Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**235**	242
Transportation	**592**	524
Total	**827**	766

Annual Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**754**	745
Transportation	**2,288**	2,046
Total	**3,042**	2,791

Regulatory Recovery Mechanisms

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.

Other Cost Recovery

Fuel Recovery Clause
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment (“PGA”) 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 subject to a cap approved annually by the FPSC.

Other Cost Recovery Clauses
The FPSC annually approves cost-recovery rates for conservation costs including a return on capital invested incurred in developing and implementing energy conservation programs. PGS has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. As part of the depreciation study settlement agreement approved by the FPSC in February 2017, the Cast Iron/Bare Steel clause was expanded to allow recovery of accelerated replacement of certain obsolete plastic pipe. PGS projects to have all cast iron and bare steel pipe removed from its system by 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

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.

Other Cost Recovery

Fuel Recovery Clause
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 charges based on next month’s expected cost of gas and any prior month under-recovery or over-recovery. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that continued use of the PGAC is reasonable and necessary. In December 2016, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2020.

Weather Normalization Mechanism
In July 2019, the NMPRC approved changes to the company’s rate design to include a Weather Normalization Mechanism. This clause is designed to lower the variability of weather impacts during the annual October through April heating season. The Weather Normalization Mechanism will make customer rates and company revenue more predictable by partially removing the impact of warmer than usual or colder than usual weather. Weather-related revenue increases or decreases experienced from October to April will be adjusted annually in October of the following heating season.

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31 2019	2018	Year ended December 31 2019	2018
Marketing and trading margin (1) (2)	**$ 28**	$ 42	**$ 31**	$ 115
Electricity and capacity sales (3) (4)	**2**	132	**118**	445
Other non-regulated operating revenue	**1**	12	**31**	47
Total operating revenues – non-regulated	**$ 31**	$ 186	**$ 180**	$ 607
Intercompany revenue (5)	**3**	10	**20**	39
Non-regulated fuel for generation and purchased power (4)(6)	**2**	68	**68**	238
Operating, maintenance and general	**27**	76	**130**	206
Depreciation and amortization	**3**	9	**11**	49
Income from equity investments	**7**	10	**32**	34
Interest expense, net	**81**	92	**337**	363
Adjusted contribution to consolidated net income (loss)	**$ (58)**	$ (28)	**$ (286)**	$ (153)
After-tax derivative mark-to-market gain (loss)	**$ 81**	$ 67	**$ 73**	$ 44
Contribution to consolidated net income (loss)	**$ 23**	$ 39	**$ (213)**	$ (109)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.24)**	$ (0.12)	**$ (1.19)**	$ (0.66)
Contribution to consolidated earnings per common share – basic	**$ 0.09**	$ 0.17	**$ (0.89)**	$ (0.47)
Adjusted EBITDA	**$ 2**	$ 50	**$ 9**	$ 198

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market gain of $119 million in Q4 2019 (2018 - $87 million gain) and a gain of $100 million for the year ended December 31,2019 (2018 – $16 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market loss of nil in Q4 2019 (2018 - $10 million gain) and a gain of $2 million for the year ended December 31, 2019 (2018 – $38 million gain).
(4) On March 29, 2019, Emera completed the sale of the NEGG facilities. Refer to the "Developments" section for further details.
(5) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.
(6) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $1 million in Q4 2019 (2018 - nil) and a $2 million loss or the year ended December 31, 2019 (2018 – $5 million gain).

Other's adjusted contribution is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31 2019	2018	Year ended December 31 2019	2018
Emera Energy	**$ 18**	$ 44	**$ 37**	$ 120
Corporate	**(75)**	(67)	**(322)**	(269)
Other	**(1)**	(5)	**(1)**	(4)
Adjusted contribution to consolidated net income (loss)	**$ (58)**	$ (28)	**$ (286)**	$ (153)

Mark-to-Market Adjustments

Emera Energy's "Marketing and trading margin", "Electricity and capacity sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by MTM adjustments. Management believes excluding the effect of MTM valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows. Variance explanations of the MTM changes for this quarter and for the year are explained in the chart below.

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities and natural gas producers in northeastern North America. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

Subsequent changes in gas price differentials, to the extent they are not offset by the accounting amortization of the gas transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial during the term of the contract, especially in the winter months of a contract when delivered volumes and market volatility are usually at peak levels. As a contract is realized, and volumes reduce, MTM volatility is expected to decrease. Ultimately, the gas transportation asset and the MTM adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM volatility resulting in gains and losses may also increase.

Net Income

Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2018	**$ 39**	**$ (109)**
Decreased marketing and trading margin - see Emera Energy below	(14)	(84)
Impact of sale of NEGG and Bayside Power, net of tax	(21)	(43)
Transaction costs related to the pending sale of Emera Maine, net of tax	(1)	(7)
Decreased income tax recovery due to 2018 recognition of Florida state tax apportionment benefit	-	(23)
Decreased income tax recovery quarter-over-quarter primarily due to the impact of effective state tax rates, partially offset by increased losses before provision for income taxes. Year-over-year increased income tax recovery primarily due to increased losses before provision for income taxes partially offset by the impact of effective state tax rates	(7)	14
Corporate share of the unrecoverable loss on GBPC facilities	(6)	(15)
Decrease in OM&G	11	10
Gain on sale of property in Florida, net of tax	-	10
Increased mark-to-market gain, net of tax, quarter-over-quarter primarily due to change in existing positions on gas contracts, partially offset by higher amortization of gas transportation assets. Year-over-year increased mark-to-market gain, net of tax, due to changes in existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019, compared to 2018, partially offset by higher amortization of gas transportation assets in 2019	14	29
Other	8	5
Contribution to consolidated net income (loss) – 2019	**$ 23**	**$ (213)**

Excluding the change in mark-to-market, Other's contribution to consolidated net income decreased by $30 million for Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, Other's contribution to consolidated net income decreased $133 million compared to the same period in 2018. The decrease in both periods was due to lower marketing and trading margin, the impact of the sale of NEGG and Bayside Power and the corporate share of the unrecoverable loss on GBPC's facilities, offset by decreased OM&G. The year-over-year decrease also included recognition of Florida state tax apportionment benefit in 2018 partially offset by the gain on sale of property in Florida.

Emera Energy

EES derives revenue and earnings from the wholesale marketing and trading of natural gas, electricity and other energy-related commodities and derivatives within the Company's risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. EES purchases and sells physical natural gas and electricity, the related transportation and transmission capacity rights, and provides related energy asset management services. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the Florida, US Gulf Coast and Midwest/Central Canadian natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

Marketing and Trading

Marketing and trading margin decreased $14 million to $28 million in Q4 2019, compared to $42 million in Q4 2018. For the year ended December 31, 2019, margin decreased $84 million to $31 million compared to $115 million in 2018. The decrease in both periods was due to less favourable market conditions, specifically lower natural gas prices and volatility and higher fixed cost commitments for gas transportation and storage assets in 2019, compared to 2018.

In March 2019, the Company completed the sale of Emera Energy's NEGG and Bayside facilities. Refer to the "Developments" section for further details.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments and select asset sales. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. Emera's subsidiaries are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment, and maintain their credit metrics.

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has a $6.9 billion capital investment plan over the 2020-to-2022 period and the potential for additional capital opportunities of $500 million to $1 billion over the forecast period. This plan includes significant rate base investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Capital expenditures at the regulated utilities are subject to regulatory approval. Emera plans to use cash from operations, debt raised at the utilities and proceeds from the Emera Maine sale, to support normal operations, repayment of existing debt and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. Emera has credit facilities with varying maturities that cumulatively provide $3.2 billion of credit. Refer to notes 22 and 24 in the consolidated financial statements for additional information regarding the credit facilities.

Emera believes its liquidity is adequate given the Company's expected operating cash flows, capital expenditures, and related financing plans.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2019 and 2018 include:

millions of Canadian dollars		**2019**		2018		$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$**	**372**	$	503	$	(131)
Provided by (used in):						
Operating cash flow before changes in working capital		**1,598**		1,806		(208)
Change in working capital		**(73)**		(116)		43
Operating activities		**1,525**		1,690		(165)
Investing activities		**(1,617)**		(2,190)		573
Financing activities		**14**		344		(330)
Effect of exchange rate changes on cash and cash equivalents		**(20)**		25		(45)
Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period	**$**	**274**	$	372	$	(98)

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $165 million to $1,525 million for the year ended December 31, 2019, compared to $1,690 million for the same period in 2018.

Cash from operations before changes in working capital decreased $208 million in 2019. The decrease was due to lower marketing and trading margin at EES and lower earnings from Emera Energy Generation as a result of the sale of NEGG. These were partially offset by higher revenue collected for the in-service of solar generation projects and lower under-recovery from customers on clause related costs at Tampa Electric.

Changes in working capital increased operating cash flows by $43 million. The increase was due to a refund of $146 million ($109 million USD) of alternative minimum tax credit carryforwards in April 2019. This was partially offset by unfavourable changes in cash collateral at NSPI and increased investment in fuel inventory at NSPI.

Cash Flow used in Investing Activities

Net cash used in investing activities decreased $573 million to $1,617 million for the year ended December 31, 2019, compared to $2,190 million in 2018. In 2019, Emera received proceeds of $875 million on dispositions, primarily from the sale of the NEGG and Bayside facilities. These proceeds were partially offset by an increase in capital expenditures.

Capital expenditures for the year ended December 31, 2019, including AFUDC, were $2,516 million compared to $2,178 million in 2018. Details of the 2019 capital spend by segment are shown below:

- $1,414 million - Florida Electric Utility (2018 – $1,235 million);
- $389 million - Canadian Electric Utilities (2018 – $350 million);
- $200 million - Other Electric Utilities (2018 – $190 million);
- $450 million - Gas Utilities and Infrastructure (2018 – $332 million); and
- $63 million - Other (2018 – $71 million).

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $330 million to $14 million for the year ended December 31, 2019, compared to $344 million for the same period in 2018. The decrease was due to repayment of corporate long-term debt, repayments at NSPI, a 2018 preferred share issuance and net repayment of committed credit facilities at NMGC. These were partially offset by proceeds from Emera's non-revolving credit facilities, issuance of long-term debt at NSPI and NMGC in 2019, the 2018 repayment of debt at TECO Finance, net borrowings from credit facilities by TEC and proceeds from Emera's ATM program.

Working Capital

As at December 31, 2019, Emera's cash and cash equivalents were $222 million (2018 – $316 million) and Emera's investment in non-cash working capital was $566 million (2018 – $449 million). Of the cash and cash equivalents held at December 31, 2019, $208 million was held by Emera's foreign subsidiaries (2018 – $280 million). A portion of these funds are invested in countries that have certain exchange controls, required approvals, and processes for repatriation. Such funds remain available to fund local operating and capital requirements unless repatriated.

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Contractual Obligations

As at December 31, 2019, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2020	2021	2022	2023	2024	Thereafter	Total
Long-term debt principal (1)	$ 550	1,665	$ 512	$ 831	$ 987	$ 10,261	$ 14,806
Interest payment obligations (2)(3)	667	621	583	558	536	7,039	10,004
Purchased power (4)(5)	210	233	237	246	249	2,228	3,403
Transportation (6)	514	398	340	281	264	2,720	4,517
Pension and post-retirement obligations (7)(8)	32	37	33	32	99	306	539
Capital projects (9)	411	109	103	86	-	-	709
Fuel, gas supply and storage	466	133	22	1	-	-	622
Asset retirement obligations	2	43	1	1	1	360	408
Long-term service agreements (10)(11)	52	37	36	27	26	100	278
Equity investment commitments (12)	240	-	-	-	-	-	240
Leases and other (13)	19	19	18	17	8	118	199
Demand side management	38	41	43	-	-	-	122
Long-term payable	5	5	5	5	-	-	20
Convertible debentures	-	-	-	-	-	1	1
	$ 3,206	$ 3,341	$ 1,933	$ 2,085	$ 2,170	$ 23,133	$ 35,868

As noted below, contractual obligations at December 31, 2019 include amounts related to Emera Maine. On completion of the sale of Emera Maine, all of the remaining future obligations related to these contractual commitments will be transferred to the buyer. Refer to the “Developments" section for additional information.

(1) Includes $518 million related to Emera Maine ($49 million in 2020; $107 million in 2022; $11 million in 2023 and $351 million thereafter).
(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2019, including any expected required payment under associated swap agreements.
(3) Includes $423 million related to Emera Maine ($22 million in 2020; $21 million in 2021; $16 million in 2022; $15 million in 2023, $15 million in 2024 and $334 million thereafter).
(4) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(5) Includes $520 million related to Emera Maine ($13 million in 2020; $23 million in 2021; $27 million in 2022; $31 million in 2023; $31 million in 2024 and $395 million thereafter).
(6) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(7) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans (excluding the possibility of wind-up), plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.
(8) Includes $65 million related to Emera Maine ($3 million in 2020; $3 million in 2021; $3 million in 2022; $4 million in 2023; $4 million in 2024 and $48 million thereafter).
(9) Includes $345 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.
(10) 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.
(11) Includes $44 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($19 million in 2020; $9 million in 2021; $8 million in 2022; and $8 million in 2023).
(12) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(13) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years from its January 15, 2018 in-service date. The UARB approved payment for 2019 was $111 million, subject to a $10 million holdback and as at December 31, 2019, $101 million has been paid. The UARB approved payment for 2020 is $145 million, subject to a holdback of up to $10 million. As part of NSPI’s 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and estimated amounts of $164 million and $162 million for 2021 and 2022, respectively. These estimated amounts are subject to review and approval by the UARB. The timing and amounts payable to NSPML for the remainder of the 37-year commitment period are dependent on regulatory filings with the UARB.

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 would 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, Emera includes the obligations within "Leases and other" in the above table.

Forecasted Gross Consolidated Capital Expenditures

2020 forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities (1)	Gas Utilities and Infrastructure	Other	Total
Generation	$ 396	$ 141	$ 96	$ -	$ 1	$ 634
New renewable generation	412	-	-	-	-	412
Transmission	91	50	9	-	-	150
Distribution	253	126	50	-	-	429
Gas transmission and distribution	-	-	-	709	-	709
Facilities, equipment, vehicles, and other	136	58	11	48	73	326
	$ 1,288	$ 375	$ 166	$ 757	$ 74	$ 2,660

(1) Includes approximately $25 million related to Emera Maine expenditures in the first quarter only.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.2 billion committed syndicated revolving bank lines of credit in either CAD or USD per the table below.

millions of dollars	**Maturity**	**Revolving Credit Facilities**	**Utilized**	**Undrawn and Available**
Emera Inc. – Operating and acquisition credit facility	June 2024	$ 900	$ 497	$ 403
TECO Finance, Inc. – in USD – Operating credit facilities	March 2020 - March 2022	900	505	395
NSPI – Operating credit facility	October 2024	600	312	288
TEC - in USD - credit facilities (1)	March 2021 - March 2022	550	349	201
NMGC – in USD – Operating credit facility	March 2022	125	7	118
Emera Maine – in USD – Operating credit facility	February 2023	80	11	69
Other - in USD - Operating credit facility	Various	32	17	15

(1) This facility is available for use by Tampa Electric and PGS. At December 31, 2019, Tampa Electric had utilized $258 million USD and PGS had utilized $91 million USD of the facility.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2019. Emera's significant covenant is listed below:

	Financial Covenant	**Requirement**	**As at December 31, 2019**
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.59 : 1

Recent significant financing activities for Emera and its subsidiaries are discussed below 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 LIBOR, prime rate or the federal funds rate, plus a margin.

On December 19, 2019, TEC increased its $325 million USD revolving credit facility by $75 million USD to $400 million USD. There were no other changes in commercial terms.

On July 24, 2019, TEC completed a $300 million USD 30-year senior notes issuance. The notes bear interest at a rate of 3.625 per cent and have a maturity date of June 15, 2050.

Canadian Electric Utilities

On November 25, 2019, NSPI amended its operating credit facility to extend the maturity from October 2023 to October 2024. All other terms of the agreement are the same.

On August 2, 2019, NSPI repaid a $95 million debenture upon maturity. The debenture was repaid using its operating credit facility.

On April 4, 2019, NSPI completed a $400 million Series AB 30-year medium term notes issuance. The notes bear interest at a rate of 3.57 per cent and have a maturity date of April 5, 2049.

Gas Utilities and Infrastructure

On December 19, 2019, NMGC completed a $80 million USD 30-year unsecured notes issuance. The notes bear interest at a rate of 3.72 per cent and have a maturity date of December 15, 2049.

On December 19, 2019, NMGC completed a $15 million USD 15-year unsecured notes issuance. The notes bear interest at a rate of 3.24 per cent and have a maturity date of December 15, 2034.

On July 31, 2019, New Mexico Gas Intermediate ("NMGI") repaid a $50 million USD note upon maturity. The note was repaid using cash on hand.

On May 17, 2019, Emera Brunswick Pipeline amended the maturity date of its $250 million Credit Agreement from February 2022 to May 2023. There were no other material changes in commercial terms.

Other Electric Utilities

On December 10, 2019, Emera Maine completed a securities issuance for $60 million USD senior unsecured notes. The 30-year notes bear interest at a rate of 3.79 per cent and will mature on December 10, 2049.

Other

On December 16, 2019, Emera entered into a $400 million non-revolving credit agreement with a maturity date of December 15, 2020. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at Bankers Acceptance rates or prime rate advances, plus a margin.

On December 2, 2019, Emera's Series G $225 million 4.83 per cent medium-term notes matured and were repaid. The notes were repaid using existing credit facilities.

On June 14, 2019, Emera US Finance LP repaid a $500 million USD note upon maturity. The note was repaid using short-term investments, temporarily held from the sale of the NEGG facilities.

On June 13, 2019, Emera extended the maturity date of its $900 million revolving credit facility from June 2020 to June 2024. There were no other significant changes in commercial terms from the prior agreement.

On March 7, 2019, TECO Energy/Finance extended the maturity date of its $500 million USD credit facility from March 8, 2019 to March 5, 2020. There were no other significant changes in commercial terms from the prior agreement.

Credit Ratings

Emera and its subsidiaries have been assigned the following senior unsecured debt ratings:

	Fitch	**S&P**	**Moody's**	**DBRS**
Emera Inc.	BBB (Stable)	BBB (Negative)	Baa3 (Stable)	N/A
TECO Energy/TECO Finance	N/A	BBB (Negative)	Baa2 (Positive)	N/A
TEC	A (Stable)	BBB+ (Negative)	A3 (Positive)	N/A
NSPI	N/A	BBB+ (Negative)	N/A	A (low) (Stable)

On December 19, 2019, Moody’s Investor Services affirmed its Baa2 senior unsecured ratings on TECO Energy/TECO Finance and TEC’s A3 senior unsecured ratings and changed its ratings outlook to positive from stable.

On November 29, 2019, DBRS Limited affirmed NSPI’s A (low) issuer and issue rating with a stable trend.

On June 27, 2019, Moody’s Investor Services affirmed Emera’s Baa3 issuer and senior unsecured ratings and Emera US Finance LP’s Baa3 guaranteed senior unsecured rating and changed its ratings outlook to stable from negative.

On June 13, 2019, Fitch Ratings assigned ratings and outlook for Emera for the first time. Emera was assigned a BBB issuer default and senior unsecured rating with stable outlook. At the same time, Fitch Ratings assigned TEC an A- issuer default rating and an A senior unsecured rating with stable outlook.

Share Capital

Emera

As at December 31, 2019, Emera had 242.48 million (2018 – 234.12 million) common shares issued and outstanding. For the year ended December 31, 2019, 8.36 million common shares were issued (2018 – 5.35 million) for net proceeds of $400 million (2018 – $215 million).

As at December 31, 2019, Emera had 41 million preferred shares issued and outstanding (2018 – 41 million).

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.

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2020 for defined benefit pension plans is expected to be $44 million (2019 – $52 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds and short-term investments. Emera reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

Emera's projected contributions to defined contribution pension plans only, are $34 million for 2020, including $2 million for a full year of contribution for Emera Maine (2019 – $34 million actual). The actual contribution is expected to be lower depending on the timing of the pending sale of Emera Maine.

Defined Benefit Pension Plan Summary

in millions of Canadian dollars					As at December 31, 2019
Plans by region	**TECO Energy Pension Plans**	**NSPI Pension Plans**	**Emera Maine Pension Plans**	**Caribbean Plans**	**Total**
Assets as at December 31, 2019	$ 1,034	$ 1,357	$ 192	$ 10	$ 2,593
Accounting obligation at December 31, 2019	1,094	1,491	222	15	2,822
Accounting expense during fiscal 2019	$ 19	$ 16	$ 2	$ 1	$ 38

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2019 totalled $740 million (2018 – $759 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 80 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

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, 2019:

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.

The Company has standby letters of credit and surety bonds in the amount of $82 million USD (December 31, 2018 - $67 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 letter of credit expires in June 2020 and is renewed annually. The amount committed as at December 31, 2019 was $52 million (December 31, 2018 - $49 million).

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 2022. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time. Emera Incorporated's common share dividends paid in 2019 were $2.3750 ($0.5875 in Q1, Q2, and Q3 and $0.6125 in Q4) per common share and $2.2825 ($0.5650 in Q1, Q2, and Q3 and $0.5875 in Q4) per common share for 2018, representing a payout ratio of 91 per cent of adjusted net income in 2019 and 79 per cent in 2018.

On September 27, 2019, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.35 to $2.45. The first quarterly dividend payment at the increased rate was paid on November 15, 2019.

TRANSACTIONS WITH RELATED PARTIES

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 $107 million for the year ended December 31, 2019 (2018 - $97 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.

Refer to the "Business Overview and Outlook - Canadian Electric Utilities - ENL" and "Contractual Obligations" sections for further details.

- 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 $63 million for the year ended December 31, 2019 (2018- $29 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, 2019 and at December 31, 2018.

ENTERPRISE RISK AND RISK MANAGEMENT

Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management. Certain risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure such risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The Company's risk management activities are focused on those areas that most significantly impact profitability, quality and consistency of income, and cash flow. In this section, Emera describes these principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, liquidity or capital resources. The nature of risk is such that no list is comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. As cost-of-service utilities with an obligation to serve customers, Tampa Electric, PGS, NMGC, NSPI, Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. The commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by changes in government and shifts in government policy. This includes initiatives regarding deregulation or restructuring of the energy industry, which could occur as a result of climate change concerns. Emera also holds investments in entities in which it has significant influence and which are subject to regulatory risk include NSPML, LIL, M&NP and Lucelec.

Deregulation or restructuring of the electric industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. Florida electric utilities, including Tampa Electric, have limited competition in their market for retail customers. A proposed constitutional initiative relating to electric utilities in Florida was rejected by the Florida Supreme Court as misleading and will not be included on ballots for the November 2020 election. The proposed amendment to the Florida Constitution would have limited the business of investor-owned utilities to construction, operation and repair of electrical transmission and distribution systems. It would have also granted customers of investor-owned utilities the right to generate electricity and to choose their electricity provider.

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

Brunswick Pipeline has a 25-year firm service agreement, expiring in 2034, with Repsol Energy Canada ("REC"). This firm service agreement was filed with the NEB, and provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

Global Climate Change Risk

The Company is subject to risks that arise or may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon emissions. City, state, provincial and federal governments have been setting policies and enacting laws and regulations to deal with climate change impacts in a variety of ways, including de-carbonization initiatives and promotion of cleaner energy and renewable energy generation of electricity. Refer to "Changes in Environmental Legislation". Insurance companies have begun to limit their exposure to coal-fired electricity generation, and are evaluating the medium and long-term impacts of climate change which may result in fewer insurers, more restrictive coverage and increased premiums. Refer to the "Markets" section below and "Uninsured Risk".

Climate change may lead to increased frequency and intensity of weather events and related impacts such as storms, ice storms, hurricanes, cyclones, heavy rainfall, extreme winds, wildfires, flooding and storm surge. The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce even greater damage to coastal generation and other facilities. Climate change is also characterized by rising global temperatures. Increased air temperatures may bring increased frequency and severity of wildfires within the Company's service territories. Refer to "Weather Risk" and "System Operating and Maintenance Risks".

In response, the Company has made significant investments to facilitate the use of renewable and lower-carbon energy including wind generation, the Maritime Link in Atlantic Canada, and solar generation and the modernization of the Big Bend Power Station in Florida. Since 2005, NSPI has reduced carbon emissions by 35 per cent, exceeding the 2030 reduction target of 30 per cent set at the COP 21 Climate Conference, and expects to achieve a greater-than 50 per cent reduction by 2030; nearly double the Government of Canada's target set under the Paris Agreement. NSPI is on track to meet a provincially-mandated target of 40 per cent renewable generation by 2020. Within Emera's natural gas utilities, there are ongoing efforts to reduce methane and carbon emissions through replacement of aging infrastructure, more efficient operations, operational and supply chain optimization and support of public policy initiatives that address the effects of climate change.

The Company's long-term capital investment plan includes significant investment across the portfolio in renewable and cleaner generation, infrastructure modernization, storm hardening, energy storage and customer-focused technologies. All of these initiatives contribute toward mitigating the potential impacts of climate change. The Company continues to engage with government, regulators, industry partners and stakeholders to share information and participate in the development of climate change related policies and initiatives.

Physical Impacts

The Company is subject to physical risks that arise, or may arise, from global climate change, including damage to operating assets from more frequent and intense weather events and from wildfires due to warming air temperatures and increasing drought conditions. Substantially all of the Company's fossil fueled generation assets are located at coastal, or near coastal, sites and as such are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding. Refer to "Weather Risk".

These risks are mitigated to an extent through features such as flood walls at certain plants and through the location of other plants on higher ground. Planned investments in under-grounding parts of the electricity infrastructure also contributes to risk mitigation as does insurance coverage (for assets other than electricity transmission and distribution assets) and regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts to smooth out the recovered costs of storm restoration over time.

Reputation

Failure to address issues related to climate change could affect Emera's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital. Refer to "Liquidity and Capital Market Risk". The Company seeks to mitigate this in part by moving away from higher-carbon generation in favour of lower-carbon generation and non-emitting renewable generation.

Markets

Changing carbon-related costs, policy and regulatory changes and shifts in supply and demand factors could lead to more expensive or more scarce products and services that are required by the Company in its operations. This could lead to supply shortages and delivery delays as well as the need to source alternate products and services. The Company seeks to mitigate these risks through close monitoring of such developments and adaptive changes to supply chain procurement strategies.

Given concerns regarding carbon-emitting generation, those assets and businesses may, over time, become difficult (or uneconomic) to insure in commercial insurance markets. In the short term this may be mitigated through increased investment in engineered protection or alternative risk financing (such as funded self-insurance or regulatory structures, including storm reserves). Longer-term mitigation may be achieved through infrastructure siting decisions and further engineered protections. This risk is also mitigated through the continued transition away from high-carbon generation sources to sources with low or zero carbon emissions.

Policy

Government and regulatory initiatives, including greenhouse gas emissions standards, air emissions standards and generation mix standards, are being proposed and adopted in many jurisdictions in response to concerns regarding the effects of climate change. In some jurisdictions, government policy has included timelines for mandated shutdowns of coal generating facilities, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and longer terms, this could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

The Company is committed to compliance with all climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance over time. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation". The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, other stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition over time to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

Regulatory

Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets. Valuation impairments could result from such regulatory outcomes. Mitigation efforts in respect of these risks include active engagement with policy makers and regulators to find mechanisms to avoid such impacts while being responsive to customers' and stakeholders' objectives.

Legal

The Company could, in the future, face litigation or regulatory action related to environmental harms from carbon emissions or climate change public disclosure issues. The Company addresses these risks through compliance with all relevant laws, emissions reduction strategies and public disclosure of climate change risks.

Water Resources

For thermal plants requiring cooling water, reduced availability of water resulting from climate change could adversely impact operations or the costs of operations. The Company seeks ways to reduce and recycle water as it does in its Polk power plant in Florida, where recovered and treated wastewater is used in operations to reduce reliance on fresh water supplies in an area where water is not as abundant as in other markets.

The Company operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and ambient air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities. The Company is reinvesting in the efficiency of certain of such facilities to increase generation capacity and continues to monitor changing hydrology patterns. Such issues may also affect the availability of third party-owned hydroelectricity purchased power sources.

Weather Risk

The Company is subject to risks that arise or may arise from weather including seasonal variations impacting energy sales, more frequent and intense weather events, changing air temperatures, wildfires and extreme weather conditions associated with climate change. Refer to “Global Climate Change Risk”.

Fluctuations in the amount of electricity or natural gas used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the Company’s utilities. For example, electrical utilities operating in the US Northeast or Atlantic Canada could see lower demand in winter months if temperatures are warmer than expected. Further, extreme weather conditions such as hurricanes and other severe weather conditions associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could have an effect on the Company’s results of operations, financial conditions or cash flows.

Extreme weather events create a risk of physical damage to the Company’s assets. High winds can impact structures and cause widespread damage to transmission and distribution infrastructure. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased intensity of flooding could adversely affect the operations of the Company’s hydroelectric facilities.

Each of Emera’s regulated electric utilities have programs for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is typically not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves or designated self-insurance funds, or after the fact through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review. The risk to generation assets is, in part, mitigated through the design, siting, construction and maintenance of such facilities, regular risk assessments, engineered mitigation, emergency storm response plans and insurance.

The risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and vegetation management programs for electric transmission and distribution facilities. If it is found to be responsible for such a fire, the Company could suffer costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially affect Emera’s business and financial results including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters, primarily related to its utility operations. This includes laws setting GHG emissions standards and air emissions standards. Emera is also subject to laws regarding waste management, wastewater discharges and aquatic and terrestrial habitats.

In 2019, NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations. This provincial carbon pricing program meets the benchmark set by the Government of Canada. In the United States, in June 2019, the Environmental Protection Agency issued the final Affordable Clean Energy ("ACE") rule. The ACE rule establishes GHG emission guidelines for states to regulate GHG emissions from existing coal-fired electricity generating units. Individual states continue to develop or administer GHG reduction initiatives. Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance.

Legislative or regulatory changes could influence decisions regarding early retirement of generation facilities and may result in stranded costs if the Company is not able to fully recover the costs and investment in the affected generation assets. Recovery is not assured and is subject to prudency review. In addition, these changes may curtail sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and in compliance with applicable legal requirements and Company policy. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance.

Cybersecurity Risk

Emera is exposed to potential risks related to cyberattacks and unauthorized access. The Company increasingly relies on information technology systems and network infrastructure to manage its business and safely operate its assets; including controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other business systems. Emera also relies on third party service providers in order to conduct business. As the Company operates critical infrastructure, it may be at greater risk of cyberattacks by third parties, which could include nation-state controlled parties.

Cyberattacks can reach the Company's networks with access to critical assets and information via their interfaces with less critical internal networks or via the public internet. Cyberattacks can also occur via personnel with direct access to critical assets or trusted networks. Methods used to attack critical assets could include general purpose or energy-sector-specific malware delivered via network transfer, removable media, viruses, attachments or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt operations or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers or the unavailability, release, destruction or misuse of critical, sensitive or confidential information. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Should such cyberattacks or unauthorized accesses materialize, the Company could suffer costs, losses and damages all, or some of which, may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially adversely affect Emera's business and financial results including its reputation and standing with customers, regulators, governments and financial markets. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. If any such security breaches occur, there is no assurance that they can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards, periodic security testing, program maturity objectives and strategy derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and information technology including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation and Northeast Power Coordinating Council. The status of key elements of the Company's cybersecurity program is reported to the Audit Committee on a quarterly basis.

Energy Consumption Risk

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, customers' focus on energy efficiency and advancements in new technologies, such as rooftop solar, electric vehicles and battery storage. Government policies promoting distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings and cash flows. The Company's rate-regulated utilities are focused on understanding customer demand, energy efficiency and government policy to ensure that the impact of these activities benefit customers, that they do not negatively impact the reliability of the energy service the utilities provide and that they are addressed through regulations.

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 will be financed through internally generated cash flows, select asset sales, short-term credit facilities, and ongoing access to capital markets. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to a number of risk factors, including financial market conditions 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. Emera is subject to risk with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

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. Emera manages this risk 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, preferred share units and deferred share units.

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 into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

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.

Emera Energy Marketing and Trading

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 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. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments, as well as its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are all used to manage and mitigate this risk.

Counterparty Risk

Emera is exposed to risk related to its reliance on certain key partners, suppliers and customers. Emera is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty's non-performance under an agreement. Emera manages this counterparty risk by monitoring significant developments with its customers, partners and suppliers. The Company also manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments may be conducted on new customers and counterparties, and deposits or collateral are requested on accounts as required.

Country Risk

Earnings outside of Canada constituted 61 per cent (all from the US) of Emera's earnings in 2019 (2018 – 69 per cent, with 65 per cent from the US and 4 per cent from the Caribbean). Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters, including climate change, or economic conditions and market conditions, and change in financial policy and availability of credit. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. Fuel contracts 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 through the use of financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Future Employee Benefit Plan Performance and Funding Risk

Emera subsidiaries have both defined benefit and defined contribution employee benefit plans that cover their employees and retirees. All defined benefit plans are closed to new entrants, with the exception of the TECO Energy Group Retirement Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. Two of the largest drivers of cost are investment performance and interest rates, which are affected by global financial and capital markets. Depending on future interest rates and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could affect Emera's cash flows, financial condition and operations.

Each of Emera's employee defined benefit pension plans are managed according to an approved investment policy and governance framework. Emera employs a long-term approach with respect to asset allocation and each investment policy outlines the level of risk which the Company is prepared to accept with respect to the investment of the pension funds in achieving both the Company's fiduciary and financial objectives. Studies are routinely undertaken every 3 to 5 years with the objective that the plans' asset allocations are appropriate for meeting Emera's long-term pension objectives.

Labour Risk

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could adversely affect the Company's operations and financial results. Emera seeks to manage this risk through maintaining competitive compensation programs, a dedicated talent acquisition team, human resources programs and practices including ethics and diversity training, employee engagement surveys, succession planning for key positions and apprenticeship programs.

Approximately 40 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

Information Technology Risk

Emera relies on various information technology systems to manage operations. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems.

Emera manages this risk through IT asset lifecycle planning and management, governance, internal auditing and testing of systems, and executive oversight. Employees with extensive subject matter expertise assist in risk identification and mitigation, project management, implementation and training. System resiliency, formal disaster recovery and backup processes, combined with critical incident response practices, ensure that continuity is maintained in the event of any disruptions.

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.

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, activities of third parties, damage to facilities, solar panels and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties and damage to the pipelines facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Refer to "Global Climate Change Risk" and "Weather Risk". Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence. Emera's operations have significant capital projects that may require approvals and permits at the federal, provincial, state, regional and local level. There can be no assurance that Emera will be able to obtain the necessary project approvals or applicable permits. Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could adversely affect the Company's results of operations and cash flows.

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. Certain facilities, in particular coal and other thermal generation, may, over time, become more difficult (or uneconomic) to insure as a result of the impact of global climate change. Refer to "Global Climate Change Risk – Markets". There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets, as is customary in the industry. The cost of this coverage is not economically viable. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred by the Company and its subsidiaries will be covered by insurance.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by Emera and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on Emera's results of operations, cash flows and financial position, if regulatory recovery is not available. A limited portion of Emera's property and casualty insurance is placed with a wholly owned captive insurance company. If a loss is suffered by the captive insurer, it is not able to recover that loss other than through future premiums.

The Company mitigates its uninsured risk by ensuring that insurance limits align with risk exposures, and for uninsured assets and operations, that appropriate risk assessments and mitigation measures are in place. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including uninsured losses.

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the Enterprise Risk Management Committee, whose responsibilities include preparing and updating a "Risk Dashboard" for the Board of Directors on a quarterly basis. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

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. 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. The Company 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 NSPI, NMGC and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled in regulated fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. Management believes any gains or losses resulting from settlement of these derivatives 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 and are recognized on the balance sheet at fair value. All gains or losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

Hedging Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to derivatives in valid hedging relationships:

As at millions of Canadian dollars		**December 31 2019**		December 31 2018
Derivative instrument liabilities (current and long-term liabilities)	**$**	**(1)**	$	(5)
Net derivative instrument liabilities	**$**	**(1)**	$	(5)

Hedging Impact Recognized in Net Income

The Company recognized gains (losses) related to the effective portion of hedging relationships under the following categories:

For the millions of Canadian dollars				Year ended December 31
		2019		2018
Operating revenues – regulated	**$**	**(3)**	$	5
Non-regulated fuel for generation and purchased power		**-**		1
Effective net gains (losses)	**$**	**(3)**	$	6

The effective net gains (losses) reflected in the above table would be offset in net income by the hedged item realized in the period.

Regulatory Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to derivatives receiving regulatory deferral:

As at millions of Canadian dollars		**December 31 2019**		December 31 2018
Derivative instrument assets (current and other assets)	**$**	**28**	$	104
Regulatory assets (current and other assets)		**80**		6
Derivative instrument liabilities (current and long-term liabilities)		**(78)**		(6)
Regulatory liabilities (current and long-term liabilities)		**(42)**		(115)
Net asset (liability)	**$**	**(12)**	$	(11)

Regulatory Impact Recognized in Net Income

The Company recognized the following net gains (losses) related to derivatives receiving regulatory deferral as follows:

For the millions of Canadian dollars		Year ended December 31 **2019**		 2018
Regulated fuel for generation and purchased power (1)	**$**	**5**	$	11
Net gains	**$**	**5**	$	11

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

HFT Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to HFT derivatives:

As at millions of Canadian dollars		**December 31 2019**		December 31 2018
Derivative instrument assets (current and other assets)	**$**	**58**	$	62
Derivative instrument liabilities (current and long-term liabilities)		**(291)**		(354)
Net derivative instrument assets (liability)	**$**	**(233)**	$	(292)

Held-for-trading Items Recognized in Net Income

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

For the millions of Canadian dollars				Year ended December 31
		2019		2018
Non-regulated operating revenues	**$**	**282**	$	193
Non-regulated fuel for generation and purchased power		**(6)**		2
Other income (expenses), net		**-**		-
Net gains (losses)	**$**	**276**	$	195

Other Derivatives Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to other derivatives:

As at millions of Canadian dollars		**December 31 2019**		December 31 2018
Derivative instrument assets (current and other assets)	**$**	**1**	$	1
Net derivative instrument assets (liabilities)	**$**	**1**	$	1

Other Derivatives Recognized in Net Income

The Company recognized in net income the following realized and unrealized gains (losses) related to other derivatives:

For the millions of Canadian dollars				Year ended December 31
		2019		2018
Operating, maintenance and general	**$**	**28**	$	-
Interest expense, net		-		(1)
Net gains (losses)	**$**	**28**	$	(1)

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). The Company's internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company's DC&P and ICFR as at December 31, 2019 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

There were no changes in the Company's ICFR, during the quarter ended December 31, 2019, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made.

Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, capitalized overhead and valuation of financial instruments. Actual results may differ significantly from these estimates.

Rate Regulation

The rate-regulated accounting policies of Emera's rate regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from accounting policies for non-rate-regulated companies. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on expectations of the future actions of the regulators. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered. The application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

The Company has recorded $1,552 million (2018 - $1,569 million) of regulatory assets and $2,181 million (2018 - $2,610 million) of regulatory liabilities as at December 31, 2019.

Accumulated Reserve – Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-asset retirement obligation costs of removal as regulatory liabilities. These costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required costs of removal of property, plant and equipment upon retirement. The companies accrue for costs of removal 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. The balance of the Accumulated reserve – cost of removal within regulatory liabilities was $891 million at December 31, 2019 (2018 - $955 million).

Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings, could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. Changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs could change the annual pension funding requirements. This could have a significant impact on the Company's annual cash requirements.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in changes to pension costs in future periods.

The Company's accounting policy is to amortize the net actuarial gain or loss, that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period (for the largest plans this is currently 9.5 years (7.5 years for 2019 benefit cost) for the Canadian plans and a weighted average of 12.4 years for the US plans). The Company's use of smoothed asset values reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

	2019		2018	
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Energy Group Retirement Plan	**4.34 % / 3.13 %**	**7.35 / 7.00 %**	3.63 %	6.85 %
TECO Energy Group Supplemental Executive Retirement Plan (1)	**4.02 %**	**N/A**	3.11% / 3.84 %	N/A
TECO Energy Group Benefit Restoration Plan (1)	**4.12 / 3.94 / 3.32 %**	**N/A**	3.26 / 3.76 / 4.01 %	N/A
TECO Energy Post-retirement Health and Welfare Plan	**4.38 %**	**N/A**	3.70 %	N/A
New Mexico Gas Company Retiree Medical Plan	**4.39 %**	**3.25 %**	3.71 %	4.00 %
NSPI	**3.83 %**	**6.00 %**	3.50 %	6.00 %
Bangor Hydro (2)	**4.19 %**	**6.35 %**	3.53 %	6.55 %
Maine Public Service (2)	**4.12 %**	**6.55 %**	3.45 %	6.55 %
GBPC Salaried	**4.25 %**	**6.00 %**	4.25 %	6.00 %
GBPC Union	**5.00 %**	**5.00 %**	5.00 %	5.00 %

(1) The discount rate and expected return on assets for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.
(2) Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged to become Emera Maine.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $84 million in 2019 (2018 - $115 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2019 benefit cost of $9 million and $6 respectively (2018 - $9 million and $6 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for Tampa Electric, PGS, NMGC, Emera Maine, BLPC, GBPC and Domlec. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2019, unbilled revenues totalled $265 million (2018 – $296 million) on total annual operating revenues of $6,111 million (2018 – $6,524 million).

Property, Plant and Equipment

Property, plant and equipment represents 57 per cent of total assets on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated property, plant and equipment are determined based on formal depreciation studies and require the appropriate regulatory approval. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense and accumulated depreciation.

Depreciation expense was $881 million for the year ended December 31, 2019 (2018 – $881 million).

Goodwill Impairment Assessments

Goodwill is subject to an annual assessment for impairment at the reporting unit level. 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. Application of the goodwill impairment test requires management judgment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. Significant assumptions used in the qualitative assessment include macroeconomic conditions, industry and market considerations and overall financial performance, among other factors.

If an entity performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, or if an entity 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. Significant assumptions used in estimating the fair value of a reporting unit include discount and growth rates, rate case assumptions, valuation of net operating losses, utility sector market performance and transactions, projected operating and capital cash flows for the relevant business and the fair value of debt.

At December 31, 2019, the Company had goodwill with a total carrying amount of $5,835 million (December 31, 2018 – $6,313 million). This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGC reporting units) and GBPC over the fair values assigned to individual assets acquired and liabilities assumed. The change in the carrying value from 2019 to 2018 was a result of the held for sale classification of Emera Maine, recognition of the GBPC impairment charge and the strengthening US dollar on the goodwill balances.

In Q4 2019, the Company performed quantitative impairment assessments at the reporting unit level. The quantitative assessments for Tampa Electric, PGS and NMGC concluded that the fair value of the reporting units exceeded their respective carrying amounts. However, it was determined that including the impact of Hurricane Dorian, the fair value of GBPC did not exceed its carrying amount. As a result of this assessment, a goodwill impairment charge of $30 million was recorded in 2019, leaving goodwill of $70 million related to GBPC as at December 31, 2019. No impairment was recorded in 2018. Refer to note 21 to the consolidated financial statements for further details.

Emera Maine's assets and liabilities are classified as held for sale, including $148 million of goodwill, and are measured at the lower of their carrying value or fair value less costs to sell. The measurement did not result in a fair value adjustment and goodwill was not impaired.

The fair market value of reporting units is subject to change from period to period as assumptions about future cash flows are required. Adverse regulatory actions, such as significant reductions in the allowed ROE at Tampa Electric, PGS, NMGC or GBPC could negatively impact goodwill in the future. In addition, changes in other fair value significant assumptions described above could also negatively impact goodwill in the future.

Long-Lived Assets Impairment Assessments

In accordance with accounting guidance for long-lived assets, the Company 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 believes accounting estimates related to asset impairments are critical estimates as the estimates are highly susceptible to change and the impact of an impairment on reported assets and earnings could be material. Management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and the current and expected market conditions in such periods. Markets can experience significant uncertainties. Estimates based on 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.

In Q4 2019, due to the damage incurred from Hurricane Dorian, the Company determined that the undiscounted expected future cash flows for GBPC's property, plant and equipment did not exceed its carrying amount. As a result of this assessment, a non-cash impairment charge of $18 million USD was recorded in 2019 based on the excess of the carrying amount of the property, plant and equipment over its estimated fair value. The charge was recorded as a regulatory asset as management anticipates that recovery of these prudently incurred costs through insurance or a regulatory process is probable. GBPC recorded an offsetting insurance receivable of $15 million USD against this regulatory asset. It is anticipated that the regulatory asset balance of $3 million USD remaining at December 31, 2019 will be recovered through insurance. No impairment was recorded in 2018.

Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, 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. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals, requires judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the “more likely than not” threshold may be recognized or continue to be recognized. Unrecognized tax benefits are evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in examinations of the Company’s tax returns.

The Company believes the accounting estimate related to income taxes is a critical estimate for several reasons. The realization of deferred tax assets is dependent upon the generation of sufficient taxable income, both operating and capital, in future periods. A change in the estimated valuation allowance could have a material impact on reported assets and results of operations. Administrative actions of the tax authorities, changes in tax law or regulation, and the uncertainty associated with the application of tax statutes and regulations could change the Company’s estimate of income taxes, including the potential for elimination or reduction of our ability to realize tax benefits and to utilize deferred tax assets.

Asset Retirement Obligations (“ARO”)

The measurement of the fair value of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with the legally obligated costs. There are uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations and advances in remediation technologies. Emera has AROs associated with the remediation of generation, transmission and distribution and pipeline assets.

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. Accretion expense is included as part of “Depreciation and amortization”. Any accretion expense not yet approved by the regulator is recorded in “Property, plant and equipment” and included in the next depreciation study. Accordingly, changes to the ARO or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

Some generation, transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. 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 when an amount can be determined.

As at December 31, 2019, the AROs recorded on the balance sheet were $185 million (2018 – $205 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $422 million (2018 - $451 million), which will be incurred between 2019 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Capitalized Overhead

Emera's rate regulated subsidiaries and regulated equity investments capitalize overhead costs that are attributable to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by the respective regulators. For the year ended December 31, 2019, $199 million of overhead costs (2018 – $187 million) were capitalized to capital assets. Any change in the methodology for the calculation and allocation of overhead costs could have a material impact on the amounts recognized as expenses versus assets.

Financial Instruments

The Company is required to determine the fair value of all derivatives except those which qualify for the normal purchase, normal sale exception. Fair value is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

Level Determinations and Classifications

The Company uses the Level 1, 2, and 3 classifications in the fair value hierarchy. The fair value measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the fair value. Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability. Only in limited circumstances does the Company enter into commodity transactions involving non-standard features where market observable data is not available or have contract terms that extend beyond five years.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2019, are described as follows:

Leases

On January 1, 2019, the Company adopted Accounting Standard Updates ("ASU") 2016-02, *Leases (Topic 842)*, including all related amendments, using the modified retrospective approach. The standard requires lessees to recognize leases on the balance sheet for all leases with a term of longer than twelve months and disclose key information about leasing arrangements.

As permitted by the optional transition method, Emera did not restate comparative financial information in the Company's consolidated financial statements, did not reassess whether any expired or existing contracts contained leases and carried forward existing lease classifications. Additionally, the Company elected to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under the leasing guidance within ASC Topic 840. The Company elected to use hindsight to determine the lease term for existing leases and elected to not separate lease components from non-lease components for all lessee and lessor arrangements.

Emera has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There were no updates to information technology systems as a result of implementation.

The Company's adoption of this new standard resulted in right-of-use ("ROU") assets and lease liabilities of approximately $58 million as of January 1, 2019. The ROU assets and lease liabilities were measured at the present value of remaining lease payments using the Company's incremental borrowing rate.

There was no impact to opening retained earnings as at January 1, 2019 or the Company's net income or cash flows for the year ended December 31, 2019 as a result of the adoption of the standard. There were no significant impacts to Emera's accounting for lessor arrangements. Refer to note 18 of the consolidated financial statements for further detail.

Targeted Improvements to Accounting for Hedging Activities

On January 1, 2019, the Company adopted ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

Cloud Computing

In August 2018, the Financial Accounting Standards Board ("FASB") issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company early adopted the standard effective January 1, 2019 and elected to apply the guidance prospectively. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

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 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.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. 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, including 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 Company adopted ASU 2016-13 effective January 1, 2020, with no significant changes to accounting and disclosure identified related to the adoption of the standard.

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, 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 will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard will be applied on both a prospective and retrospective basis. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2019**	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Operating revenues	**$ 1,616**	$ **1,299**	$ 1,378	$ 1,818	$ 1,799	$ 1,495	$ 1,423	$ 1,807
Net income attributable to common shareholders	**193**	**55**	103	312	231	118	90	271
Adjusted net income attributable to common shareholders	**145**	**122**	130	224	167	191	111	202
Earnings per common share – basic	**0.79**	**0.23**	0.43	1.32	0.98	0.51	0.38	1.17
Earnings per common share – diluted	**0.80**	**0.23**	0.43	1.32	0.98	0.50	0.38	1.17
Adjusted earnings per common share – basic	**0.60**	**0.51**	0.54	0.95	0.71	0.82	0.48	0.87

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. The first quarter provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. Seasonal and other weather patterns, as well as the number and severity of storms, can affect the demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the "Significant Items Affecting Earnings" section.