Management's Discussion & Analysis

As at November 7, 2019

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 third quarter and year-to-date of 2019 relative to the same periods in 2018; and its financial position as at September 30, 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 unaudited condensed consolidated interim financial statements and supporting notes as at and for the nine months ended September 30, 2019; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2018. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

Effective January 1, 2019, Emera has 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, Emera Utility Services Inc. and corporate holding and financing companies.

All comparative segment financial information for the three and nine months ended September 30, 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
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; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty credit risk; commercial relationship 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 jurisdictions provide generally stable regulatory and economic environments.

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, including 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 generally hedges transactional exposure and generally does not hedge 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 changes. Emera's efforts to fund investments in renewable and technology assets with related fuel or operating cost savings balances the opportunity with managing rate pressure and affordability for customers.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the recently completed 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:

- 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.

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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Net income attributable to common shareholders	**$ 55**	$ 118	**$ 470**	$ 479
After-tax mark-to-market gain (loss)	**$ (67)**	$ (73)	**$ (6)**	$ (25)
Adjusted net income attributable to common shareholders	**$ 122**	$ 191	**$ 476**	$ 504
Earnings per common share – basic	**$ 0.23**	$ 0.51	**$ 1.97**	$ 2.06
Adjusted earnings per common share – basic	**$ 0.51**	$ 0.82	**$ 1.99**	$ 2.17

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 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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Net income (1)	**$ 78**	$ 141	**$ 518**	$ 516
Interest expense, net	**183**	176	**557**	527
Income tax expense (recovery)	**(49)**	(33)	**18**	29
Depreciation and amortization	**226**	236	**678**	687
EBITDA	**438**	520	**1,771**	1,759
Mark-to-market gain (loss), excluding income tax and interest	**(96)**	(105)	**(11)**	(36)
Adjusted EBITDA	**$ 534**	$ 625	**$ 1,782**	$ 1,795

(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 Island as a Category 5 hurricane, causing significant damage across the island. Emera's Q3 2019 earnings decreased by approximately $16 million ($0.07 per common share), compared to Q3 2018, as a result of the impact of the hurricane. GBPC's earnings decreased by $7 million for the quarter due to reduced load as storm restoration efforts were underway. In addition, Emera recorded a corporate loss of $9 million in Q3 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 losses decreased $6 million to $67 million in Q3 2019, compared to $73 million in Q3 2018. Mainly related to Emera Energy, this decrease was due to changes in existing positions on gas contracts, partially offset by higher amortization of gas transportation assets in 2019. Year-to-date, after-tax mark-to-market losses decreased $19 million to $6 million in 2019, compared to $25 million for the same period in 2018. Mainly related to Emera Energy, this decrease 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.

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 September 30		Nine months ended September 30	
Adjusted net income	**2019**	2018	**2019**	2018
Florida Electric Utility	**$ 153**	$ 143	**$ 339**	$ 298
Canadian Electric Utilities	**33**	36	**171**	174
Other Electric Utilities	**23**	31	**62**	64
Gas Utilities and Infrastructure	**25**	15	**132**	93
Other	**(112)**	(34)	**(228)**	(125)
Adjusted net income attributable to common shareholders	**$ 122**	$ 191	**$ 476**	$ 504
After-tax mark-to-market gain (loss)	**(67)**	(73)	**(6)**	(25)
Net income attributable to common shareholders	**$ 55**	$ 118	**$ 470**	$ 479

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2018	**$ 191**	**$ 504**
Florida Electric Utility - increased earnings due to increased contribution from solar investments and customer growth	10	41
NMGC tax benefit related to change in treatment of net operating loss ("NOL") carryforwards, and Q2 2019 recognition of tax reform benefits, of which $8 million relates to 2018	7	19
Gas Utilities and Infrastructure - increased earnings due to favourable weather in New Mexico in the first half of 2019, customer growth at PGS and lower depreciation and amortization at PGS	3	20
Gain on sale of property in Florida	-	10
Increased preferred stock dividends	(1)	(9)
Transaction costs related to the pending sale of Emera Maine	(2)	(6)
Impact of Hurricane Dorian related to GBPC. Refer to the "Significant Items Affecting Earnings" and "Developments" sections	(16)	(16)
Decreased earnings from Emera Energy Generation due to the sale of New England Gas Generating Facilities ("NEGG") and Bayside generation facilities	(18)	(22)
Decreased earnings at Emera Energy Services	(20)	(43)
2018 recognition of Florida state tax apportionment benefit	(23)	(23)
Other variances	(9)	1
Adjusted net income – 2019	**$ 122**	**$ 476**

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

For the millions of Canadian dollars	Nine months ended September 30	
	2019	2018
Operating cash flow before changes in working capital	**$ 1,182**	$ 1,237
Change in working capital	**128**	156
Operating cash flow	**$ 1,310**	$ 1,393
Investing cash flow	**$ (786)**	$ (1,565)
Financing cash flow	**$ (546)**	$ 121

As at millions of Canadian dollars	**September 30 2019**	December 31 2018
Total assets	**$ 31,565**	$ 32,314
Total long-term debt (including current portion)	**$ 14,377**	$ 15,411

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 September 30		Variance	Nine months ended September 30		Variance
	2019	2018		**2019**	2018	
Operating revenues	**$ 1,299**	$ 1,495	$ (196)	**$ 4,495**	$ 4,725	$ (230)
Operating expenses	**1,117**	1,257	140	**3,531**	3,758	227
Income from operations	**182**	238	(56)	**964**	967	(3)
Income from equity investments	**38**	41	(3)	**118**	121	(3)
Other income (expenses), net	**(8)**	5	(13)	**11**	(16)	27
Interest expense, net	**183**	176	(7)	**557**	527	(30)
Income tax expense (recovery)	**(49)**	(33)	16	**18**	29	11
Net income	**78**	141	(63)	**518**	516	2
Net income attributable to common shareholders	**55**	118	(63)	**470**	479	(9)
After-tax mark-to-market gain (loss)	**(67)**	(73)	6	**(6)**	(25)	19
Adjusted net income attributable to common shareholders	**$ 122**	$ 191	$ (69)	**$ 476**	$ 504	$ (28)
Earnings per common share – basic	**$ 0.23**	$ 0.51	$ (0.28)	**$ 1.97**	$ 2.06	$ (0.09)
Earnings per common share – diluted	**$ 0.23**	$ 0.50	$ (0.27)	**$ 1.96**	$ 2.05	$ (0.09)
Adjusted earnings per common share – basic	**$ 0.51**	$ 0.82	$ (0.31)	**$ 1.99**	$ 2.17	$ (0.18)
Dividends per common share declared	**$ 1.2000**	$ 1.1525	$ 0.0475	**$ 2.3750**	$ 2.2825	$ 0.0925
Adjusted EBITDA	**$ 534**	$ 625	$ (91)	**$ 1,782**	$ 1,795	$ (13)

Operating Revenues

For the third quarter of 2019, operating revenues decreased $196 million compared to the third quarter in 2018. Absent decreased mark-to-market losses of $9 million, operating revenues decreased $205 million due to:

- $106 million decrease in the Other segment due to the sale of NEGG;
- $66 million decrease at Florida Electric Utility due to a reduction in base rates as a result of US tax reform and lower clause revenues;
- $29 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;
- $14 million decrease at NSPI, mainly due to decreased industrial and commercial class sales volumes; and
- $8 million decrease in Other Electric Utilities due to lower sales at GBPC as a result of the impact of Hurricane Dorian.

These impacts were partially offset by an increase of:

- $29 million at Florida Electric Utility as a result of higher base revenues related to in-service of solar generation projects and the impact of a weaker Canadian dollar.

Year-to-date in 2019, operating revenues decreased $230 million compared to the same period in 2018. Absent decreased mark-to-market losses of $25 million, operating revenues decreased by $255 million due to:

- $197 million decrease in the Other segment due to the sale of NEGG;
- $153 million decrease at Florida Electric Utility due to lower base rates as a result of US tax reform and lower clause revenues;
- $70 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
- $15 million decrease in PGS due to lower base rates to reflect the impact of tax reform, less favourable weather in Florida, lower off-system sales and lower clause-related revenues.

These impacts were partially offset by increases of:

- $119 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;
- $45 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; and
- $11 million at Canadian Electric Utilities as a result of increased sales volume at NSPI due to weather and increased fuel-related pricing, partially offset by the impact of the Maritime Link Assessment.

Operating Expenses

For the third quarter of 2019, operating expenses decreased $140 million compared to the third quarter of 2018 due to:

- $75 million decrease in the Other segment primarily due to the sale of NEGG;
- $51 million decrease at Florida Electric Utility as a result of decreased operating, maintenance and general ("OM&G") expenses due to the regulatory agreement to net storm costs and tax reform benefits in 2018 and lower fuel costs; and
- $28 million decrease at Canadian Electric Utilities primarily due to the timing of regulatory deferrals.

These impacts were partially offset by an increase of:

- $28 million at Canadian Electric Utilities primarily due to higher storm costs as a result of the impact of post-tropical storm Dorian.

Year-to-date, operating expenses decreased $227 million compared to the same period of 2018. Absent increased mark-to-market gains of $6 million, operating expenses decreased $233 million due to:

- $153 million decrease in the Other segment as a result of the sale of NEGG; and
- $92 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.

These impacts were partially offset by an increase of:

- $35 million at Canadian Electric Utilities primarily due to higher storm costs as a result of the impact of post-tropical storm Dorian.

Other Income (Expenses), Net

The decrease in other income (expenses), net for the third quarter was primarily due to the corporate loss recorded by Emera in Q3 2019 for the corporate share of the unrecoverable loss on GBPC facilities, as a result of the impact of Hurricane Dorian. Refer to the "Significant Items Affecting Earnings" and "Developments" sections. Year-to-date in 2019, the increase was due to lower non-service pension costs at NSPI and the gain on sale of property in Florida, partially offset by the impact of Hurricane Dorian.

Interest Expense

The increase in interest expense, net for the third quarter and year-to-date compared to 2018 was primarily due to higher borrowings at Florida Electric Utility and Canadian Electric Utilities and a weaker Canadian dollar.

Income Tax Expense (Recovery)

The decrease in income taxes for the third quarter in 2019, compared to the same period in 2018 was primarily due to decreased income before provision for income taxes, a change in treatment of NMGC net operating loss (“NOL”) carryforwards, increased deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities, and increased amortization of deferred income tax regulatory liabilities. This was partially offset by the remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors in 2018, which resulted in recognition of a benefit in Q3 2018. Year-to-date in 2019, income taxes also decreased due to an increase in the proportion of income earned in foreign jurisdictions with lower tax rates.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the third quarter of 2019, net income attributable to common shareholders was favourably impacted by the $6 million decrease in after-tax mark-to-market losses, primarily related to Emera Energy. Absent the mark-to-market changes, adjusted net income attributable to common shareholders decreased $69 million. The decrease was due to lower contributions from Emera Energy, the 2018 recognition of Florida state tax apportionment benefits and the impact of Hurricane Dorian related to GBPC, partially offset by higher contributions from Florida Electric Utility and Gas Utilities and Infrastructure.

Year-to-date in 2019, net income attributable to common shareholders was favourably impacted by the $19 million decrease in after-tax mark-to-market losses primarily related to Emera Energy. Absent the favourable mark-to-market changes, adjusted net income attributable to common shareholders decreased $28 million. The decrease was due to lower contributions from Emera Energy, the 2018 recognition of Florida state tax apportionment benefits, the impact of Hurricane Dorian related to GBPC and increased preferred dividends. 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 third quarter and year-to-date 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 September 30		Nine months ended September 30		Year ended December 31
	2019	2018	**2019**	2018	2018
Weighted average CAD/USD	**$ 1.32**	$ 1.31	**$ 1.33**	$ 1.29	$ 1.30
Period end CAD/USD exchange rate	**$ 1.32**	$ 1.29	**$ 1.32**	$ 1.29	$ 1.36

The weakening of the CAD had minimal impact on earnings and increased adjusted earnings by $1 million in Q3 2019, compared to Q3 2018. The weakening of the CAD increased earnings by $14 million and adjusted earnings by $13 million year-to-date in 2019, compared to the same period in 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 uses short-term foreign currency derivative instruments to hedge specific transactions. 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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Florida Electric Utility	**$ 116**	$ 109	**$ 255**	$ 230
Other Electric Utilities	**18**	23	**47**	49
Gas Utilities and Infrastructure (1)	**12**	8	**82**	57
	146	140	**384**	336
Other segment (2)	**(56)**	(20)	**(131)**	(55)
Total (3)	**$ 90**	$ 120	**$ 253**	$ 281

(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.

BUSINESS OVERVIEW AND OUTLOOK

Effective January 1, 2019, Emera has 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.

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 anticipates earning within its allowed ROE range in 2019 and expects rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida. Assuming normal weather in the remainder of 2019, Tampa Electric sales volumes are expected to be consistent with 2018 which benefited from favourable weather in the second half of the year.

On October 17, 2019, the FPSC approved the tariffs on Tampa Electric's third tranche of its Solar Base Rate Adjustment ("SoBRA"). This SOBRA tranche, effective January 1, 2020, represents 149 MW and $27 million USD annually in estimated revenue requirements. Tampa Electric expects to file its fourth SoBRA petition for the January 1, 2021 tranche in June 2020.

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 and associated rates with the FPSC in 2020.

In September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs of approximately $102 million USD. On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric allowing the utility to net the amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers. On May 21, 2019, the FPSC approved Tampa Electric's settlement agreement with consumer parties regarding eligibility of these storm costs. As a result, Tampa Electric will refund $12 million USD to customers in January 2020, resulting in minimal impact to earnings.

In 2019, capital expenditures in the Florida Electric Utility segment are expected to be approximately $1.1 billion USD (2018 - $940 million USD), including allowance for funds used during construction ("AFUDC"). Capital projects include supporting system reliability and growth, including investments in the modernization of the Big Bend Power Station, which received final state approval on July 25, 2019, solar projects and advanced metering infrastructure ("AMI"). AFUDC will be earned on these projects during the construction periods.

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 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.
    - The Maritime Link entered service on January 15, 2018 and provides for the transmission of energy between Newfoundland and Nova Scotia, as well as improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill hydroelectricity generation project is complete.
    - Construction of the LIL is complete and Nalcor Energy ("Nalcor") recognized the first flow of energy from Labrador to Newfoundland in June 2018. Nalcor continues to work towards commissioning the LIL, which it forecasts to be operational in 2020.

NSPI

NSPI anticipates earning within its allowed ROE range in 2019 and expects modest rate base growth which will deliver a similar modest increase in earnings.

In September 2019, post-tropical storm Dorian struck Nova Scotia, with sustained hurricane force winds. The storm caused widespread damage to NSPI's transmission and distribution systems. The total cost of the restoration is expected to be approximately $39 million. At September 30, 2019, $23 million of this estimated total cost 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 absorbed by some of the excess non-fuel revenues that were recorded to date in 2019. Any excess non-fuel revenues that are available at the end of the fiscal year will be returned to customers through the fuel adjustment mechanism ("FAM"). Refer to the "Developments" section for further details.

On June 27, 2019, NSPI filed an application for a three-year fuel stability plan with the UARB and on October 3, 2019, NSPI filed additional reply evidence in support of the application. If this application is approved, it will result in an annual rate increase averaging 1.9 per cent per year for the 2020 through 2022 period to recover fuel costs within the FAM. A regulatory hearing was held on October 15, 2019 with a decision on the application expected from the UARB by the end of 2019.

NSPI is subject to environmental laws and regulations as 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, maximizing efficiency of emission control measures and minimizing customer cost. NSPI anticipates that costs prudently incurred to achieve legislated reductions will be recoverable from customers 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 Province of Nova Scotia has enacted laws and regulations that have been found to be equivalent to the federal regulations. The proposed renewal of the Canada-Nova Scotia Equivalency Agreement is expected to be finalized by the end of 2019. This agreement, as proposed, will allow NSPI to achieve compliance with federal greenhouse gas 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.

On October 23, 2019, the Province of Nova Scotia introduced Bill 213, "The Sustainable Development Goals Act," setting a goal of net-zero GHG emissions by 2050. It is currently before the legislature and is subject to proclamation. NSPI has and will continue to participate in any consultation process for this Bill.

NSPI has completed registration under the Nova Scotia Cap-and-Trade Program Regulations and received its 2019 granted emissions allowances in April 2019. These 2019 allowances will be used in 2019 or allocated to other years in the initial four-year compliance period of 2019 through 2022. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's Pan-Canadian Framework on Clean Growth and Climate Change, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable from customers under NSPI's regulatory framework.

In May 2019, Nova Scotia Environment advised NSPI that it intends to propose amendments to Nova Scotia's Air Quality Regulations (the "Regulations") respecting sulphur dioxide ("SO_2") emissions which will lessen the reduction in the SO_2 emissions for the 2020 through 2022 fuel stability period. The Regulations have been driving a steady decrease in SO_2 emissions since 2005. The current Regulations call for another round of decreases starting in 2020 based on the assumption that Muskrat Falls would be online by 2020. Given the delay with Muskrat Falls, the provincial government is allowing NSPI near-term flexibility with emissions in order to avoid significant rate increases for Nova Scotians, while continuing Nova Scotia's downward trend with SO_2 emissions. NSPI has incorporated the impact of these changes into the fuel stability plan application that was filed with the UARB on June 27, 2019.

NSPI continues to 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 2019, NSPI expects to invest approximately $400 million (2018 - $348 million), including AFUDC, in capital projects to support system reliability and AMI.

ENL

Equity earnings from NSPML and LIL combined are expected to be modestly higher in 2019, compared to 2018. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Condensed Consolidated Balance Sheets.

NSPML

Equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. The approved ROE is 9 per cent.

NSPML has UARB approval to collect $111 million from NSPI for the recovery of costs associated with the Maritime Link in 2019, which is currently included in NSPI rates. This payment is subject to a $10 million holdback. On June 14, 2019, NSPML filed an interim assessment application requesting recovery of 2020 costs of approximately $145 million from NSPI, subject to a $10 million holdback. NSPI has included the difference of $34 million in its proposed fuel stability plan filed with the UARB. A decision by the UARB is expected in Q4 2019.

In 2019, NSPML expects to invest approximately $35 million (2018 - $15 million) in capital.

LIL

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 $568 million, and is forecasted to be $579 million by the end of 2019, comprised of $410 million in equity contribution and an estimated $169 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $600 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.

Other Electric Utilities

Other Electric Utilities includes:

- Emera Maine, a regulated transmission and distribution electric utility in the State of Maine. On March 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in late 2019, subject to MPUC approval. Refer to the “Developments” section for further details.
- Emera (Caribbean) Incorporated (“ECI”), a holding company with regulated electric utilities, BLPC, a vertically integrated regulated electric utility on the island of Barbados, and GBPC, a vertically integrated regulated electric utility on Grand Bahama Island. ECI also holds:
    - a 51.9 per cent interest in Domlec, a vertically integrated regulated electric utility on the island of Dominica; and
    - a 19.1 per cent equity interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia.

Other Electric Utilities’ earnings are expected to decrease over the prior year due to lower earnings from ECI’s utilities as a result of the impact of Hurricane Dorian on GBPC, as discussed below, and modest growth in Emera Maine. The sale of Emera Maine is expected to occur in late 2019, resulting in approximately a year of earnings contribution for 2019. Emera Maine’s 2019 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in modest growth in earnings.

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. Restoration efforts are well underway. GBPC has restored power to all customers who requested power and are able to receive it and as of September 30, 2019, power was restored to approximately 85 per cent of its customers. It is currently estimated that restoration costs for GBPC self-insured assets will be approximately $12 million USD. At September 30, 2019, approximately $8 million USD of self-insured storm restoration costs incurred to date were recorded as a regulatory asset with minimal impact to earnings. Management anticipates that recovery of these self-insured costs through a regulatory process is probable. The impact of Hurricane Dorian could adversely affect GBPC’s future earnings and impairment of its assets and goodwill will be assessed. The outcome of this assessment cannot be reasonably determined or estimated at this time, therefore no impairment was recorded in Q3 2019. The Company expects to complete its impairment analysis in Q4 2019. Refer to the “Developments” section for further details.

In 2019, capital expenditures in the Other Electric Utilities segment are expected to be approximately $160 million USD (2018 – $144 million USD). Emera Maine will invest primarily in transmission and distribution projects supporting normal system reliability. ECI’s utilities are forecasting capital investment in more efficient and cleaner sources of generation, including renewables and battery storage.

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.

Gas Utilities and Infrastructure earnings are anticipated to increase over the prior year. PGS anticipates earning within its allowed ROE range in 2019 and expects rate base and earnings to be higher than prior years. PGS expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. PGS sales volumes are expected to increase at a lower rate in 2019, as 2018 energy sales benefited from favourable weather. NMGC expects earnings and rate base to be higher than prior years due to tax reform benefits recorded in Q2 2019 and a change in the treatment of NOL carryforwards recorded in Q3 2019, both of which are discussed below; and colder weather throughout Q1 2019. Customer growth rates are expected to be consistent with 2018, reflecting expectations for housing starts and new connections.

On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019, and allowed NMGC to retain tax reform benefits realized from January 1, 2018 to the effective date of the new rates. The new rates are being phased in over two years and are expected to result in an annual revenue increase of approximately $3 million USD. The impact of the retention of the tax reform benefits resulted in an increase in earnings of $9 million USD in Q2 2019, of which $6 million USD relates to 2018. The NMPRC also approved the utility's proposed weather adjustment mechanism. Beginning in August 2019, the NMPRC approved a change in the treatment of NOL carryforwards. As a result of this change, a tax benefit of approximately $5 million USD was recognized in Q3 2019.

In 2019, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $340 million USD (2018 - $254 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will complete planning phases of the Santa Fe Mainline Looping project in 2019, and will continue to invest in system improvements.

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;
    - Emera Energy Generation ("EEG"), a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada. In March 2019, Emera completed the sale of the NEGG and Bayside facilities. Refer to the "Developments" section for further details; 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.
- Emera Utility Services ("EUS"), a utility services contractor primarily operating in Atlantic Canada. In Q2 2019, Emera entered into an agreement to sell its EUS equipment. The transaction is expected to close in late 2019. EUS ceased operations on September 30, 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. Under normal market conditions, 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. Based on results year-to-date, EES expects to fall short of the low end of its normal range for 2019 but maintain profitability.

The Other segment is expected to contribute positively to earnings in 2019 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 increase over the prior year, primarily due to lower contribution from EES, as discussed above; the sale of the NEGG facilities, resulting in only three months of earnings contribution in 2019; and higher corporate costs in 2019. Corporate costs are expected to be higher due to increased preferred dividend expense as a result of additional preferred shares issued in Q2 2018, the corporate share of the unrecoverable loss related to the impact of Hurricane Dorian on GBPC, and lower tax recoveries. Tax recoveries are expected to be lower as a result of the benefit recognized in Q3 2018 due to a change in Florida state tax apportionment factors, which resulted in remeasurement of certain deferred tax balances.

In 2019, capital expenditures in the Other segment are expected to be approximately $60 million (2018 - $75 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2018 and September 30, 2019 include:

millions of Canadian dollars	Total Increase (Decrease)	Increase (Decrease) due to Held for Sale classification (1)	Other Increase (Decrease)	Explanation of Other Increase (Decrease)
Assets				
Regulatory assets (current and long-term)	**$ (50)**	**(130)**	**$ 80**	Increased due to deferred income tax regulatory asset and 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)	**(367)**	**(81)**	**(286)**	Decreased due to lower commodity prices and lower cash collateral positions at Emera Energy, changes in corporate alternative minimum tax credit carryforwards and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Assets held for sale (current and long-term), net of liabilities	**(89)**	**719**	**(808)**	Decreased due to completion of the sale of the NEGG facilities.
Property, plant and equipment, net of accumulated depreciation and amortization	**(845)**	**(1,311)**	**466**	Increased due to additions at Tampa Electric, PGS and NSPI partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Goodwill	**(334)**	**(151)**	**(183)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.

Liabilities and Equity				
Short-term and long-term debt (including current portion)	**(1,262)**	**(515)**	**(747)**	Repayment of Emera US Finance LP USD note upon maturity, the effect of a stronger CAD on the translation of Emera's foreign affiliates and repayments by NSPI and NMGC, partially offset by issuances at NSPI and Tampa Electric.
Accounts payable	**(228)**	**(30)**	**(198)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries, lower commodity prices at Emera Energy and lower cash collateral positions at NSPI and Emera Energy, partially offset by an increase at Tampa Electric due to timing of payments for solar and Big Bend modernization costs.
Deferred income tax liabilities, net of deferred income tax assets	**(150)**	**(204)**	**54**	Increased due to tax deductions in excess of accounting depreciation related to property, plant, and equipment, and net utilization of tax loss carryforwards, partially offset by increased income tax credits related to solar projects at Tampa Electric.
Regulatory liabilities (current and long-term)	**(345)**	**(156)**	**(189)**	Decreased primarily due to deferrals related to derivative instruments, fuel adjustment mechanism and cost of removal at NSPI, and the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Pension and post-retirement liabilities	**(122)**	**(71)**	**(51)**	Effect of a stronger CAD on the translation of Emera's foreign affiliates.
Other liabilities (current and long-term)	**311**	**(24)**	**335**	Increased due to timing of Emera's dividend payments and investment tax credits related to solar projects at Tampa Electric, partially offset by the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Common stock	**299**	**-**	**299**	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	**(177)**	**-**	**(177)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Retained earnings	**(95)**	**-**	**(95)**	Decreased due to dividends paid in excess of net income.

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at September 30, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to the "Developments" section and note 4 in the condensed consolidated financial statements for further details.

DEVELOPMENTS

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 will be effective November 15, 2019. Emera extended its four to five per cent annual dividend growth rate target through to 2022.

Hurricane Dorian

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

GBPC - On September 1, 2019, Dorian struck Grand Bahama Island as a Category 5 hurricane, with sustained winds of approximately 285 kilometres per hour. The hurricane stalled over the island for several days, causing significant damage to, or destruction of, homes and businesses served by GBPC. GBPC's generation, transmission and distribution assets sustained damage, including the effect of flooding that resulted from storm surge and rain. All 19,000 of GBPC's customers lost power following the storm. The Company's restoration plan is well underway and by September 30, 2019, power was restored to all customers who were able to receive power, or approximately 16,000 customers.

GBPC maintains insurance for its generation facilities and, 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 $12 million USD. At September 30, 2019, the Company incurred and recorded $8 million USD of this estimated cost. The $8 million USD was recorded as a regulatory asset as management anticipates that recovery of these prudently incurred costs through a regulatory process is probable. Management is working with GBPC's insurance companies to assess the damage to its generation assets. It is anticipated that this damage will be covered by insurance, with the exception of $5 million USD, which is GBPC's share of the insurance deductible, and which has not yet been recorded. In addition, Emera recorded a corporate loss of $9 million ($7 million USD) in Q3 2019, in the Other segment, for the corporate share of the unrecoverable loss on GBPC's facilities.

At September 30, 2019, GBPC total assets were $465 million ($351 million USD), excluding goodwill, and $101 million ($76 million USD) of Emera's goodwill was related to GBPC. The impact of Hurricane Dorian could adversely affect GBPC's future earnings and impairment of some of its assets and goodwill could occur. The outcome cannot be reasonably determined or estimated at this time, therefore no impairment was recorded in Q3 2019. The Company expects to complete its impairment analysis in Q4 2019.

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. The total cost of the restoration is expected to be approximately $39 million. At September 30, 2019, $23 million of this estimated total cost 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 absorbed by some of the excess non-fuel revenues that were recorded to date in 2019. Any excess non-fuel revenues that are available at the end of the fiscal year will be returned to customers through the FAM.

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 September 30, 2019, the storm reserve regulatory liability balance was $63 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 Q3 2019, approximately 0.9 million common shares were issued under the ATM Program at an average price of $56.76 per share for gross proceeds of $50 million ($49.4 million net of issuance costs). As at September 30, 2019, an aggregate gross sales limit of $550 million remains available for issuance under the ATM program.

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 late 2019, 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, with 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)	0.88	49
Issued for cash under Purchase Plans at market rate	3.04	153
Discount on shares purchased under Dividend Reinvestment Plan	-	(7)
Options exercised under senior management stock option plan	2.53	102
Employee Share Purchase Plan	-	1
Balance, September 30, 2019	**240.60**	**$ 6,115**

(1) As at September 30, 2019, a total of 0.88 million common shares have been issued through Emera's at-the-market equity program ("ATM Program") at an average price of $56.76 per share for gross proceeds of $50 million ($49.4 million net of issuance costs).

As at November 4, 2019, the amount of issued and outstanding common shares was 241.1 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 September 30, 2019 was 241.0 million (2018 – 233.7 million) and for the nine months ended September 30, 2019 was 238.9 million (2018 – 232.4 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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 559**	$ 593	**$ 1,492**	$ 1,565
Regulated fuel for generation and purchased power	**168**	190	**439**	482
Contribution to consolidated net income	**$ 116**	$ 109	**$ 255**	$ 230
Contribution to consolidated net income – CAD	**$ 153**	$ 143	**$ 339**	$ 298
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.63**	$ 0.61	**$ 1.42**	$ 1.28
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.32**	$ 1.29	**$ 1.33**	$ 1.26
EBITDA	**$ 249**	$ 237	**$ 641**	$ 590
EBITDA – CAD	**$ 331**	$ 311	**$ 853**	$ 762

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2018	**$ 109**	**$ 230**
Decreased operating revenues - see Operating Revenues - Regulated Electric below	(34)	(73)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	22	43
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	27	77
Increased depreciation and amortization due to increased property, plant and equipment	(7)	(18)
Increased interest expense in support of increased capital spending	(6)	(12)
Decreased other income as the result of lower AFUDC earnings due to a lower number of solar projects under construction in Q3 2019	(4)	-
Decreased income tax expense primarily due to increased amortization of deferred income tax regulatory liabilities resulting from tax reform, higher investment tax credits related to solar projects and a reduction in the Florida state corporate income tax rate	8	4
Other	1	4
Contribution to consolidated net income – 2019	**$ 116**	**$ 255**

Florida Electric Utility's CAD contribution to consolidated net income increased $10 million in Q3 2019, compared to Q3 2018. Year-to-date, Florida Electric Utility's CAD contribution to consolidated net income increased $41 million in 2019. Increases in both periods were due to higher base revenues related to the in-service of solar generation projects and customer growth. These increases were partially offset by higher depreciation expense and higher interest expense. 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 three and nine months ended September 30, 2019 by $2 million and $8 million respectively.

Operating Revenues – Regulated Electric

Beginning January 1, 2019, as approved by the FPSC, base rates at Tampa Electric were lowered by $103 million annually to reflect the impact of tax reform, resulting in a $27 million decrease in revenue in Q3 2019, and a $74 million decrease year-to-date.

Electric revenues decreased $34 million to $559 million in Q3 2019, compared to $593 million in Q3 2018. Year-to-date, electric revenues decreased $73 million to $1,492 million in 2019, compared to $1,565 million for the same period in 2018. The decreases in both periods were due to lower clause revenues, lower base rates as a result of US tax reform and less favourable weather, 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:

Q3 Electric Revenues
millions of US dollars

	2019	2018
Residential	**$ 325**	$ 331
Commercial	**160**	163
Industrial	**41**	43
Other (1)	**33**	56
Total	**$ 559**	$ 593

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

YTD Electric Revenues
millions of US dollars

	2019	2018
Residential	**$ 792**	$ 802
Commercial	**421**	435
Industrial	**117**	121
Other (1)	**162**	207
Total	**$ 1,492**	$ 1,565

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

Q3 Electric Sales Volumes
Gigawatt hours ("GWh")

	2019	2018
Residential	**2,976**	2,944
Commercial	**1,791**	1,791
Industrial	**519**	546
Other	**548**	579
Total	**5,834**	5,860

YTD Electric Sales Volumes
GWh

	2019	2018
Residential	**7,281**	7,098
Commercial	**4,704**	4,698
Industrial	**1,520**	1,524
Other	**1,515**	1,705
Total	**15,020**	15,025

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $22 million to $168 million in Q3 2019, compared to $190 million in Q3 2018. Year-to-date, regulated fuel for generation and purchased power decreased $43 million to $439 million in 2019, compared to $482 million in the same period in 2018. The decrease in both periods was due to increased use of lower-cost natural gas and increased solar generation.

Q3 Production Volumes
GWh

	2019	2018
Natural gas	**5,006**	4,698
Coal	**219**	775
Oil and petcoke	**-**	231
Solar	**210**	26
Purchased power	**657**	365
Total	**6,092**	6,095

YTD Production Volumes
GWh

	2019	2018
Natural gas	**13,439**	11,937
Coal	**891**	2,658
Oil and petcoke	**-**	472
Solar	**587**	50
Purchased power	**1,080**	727
Total	**15,997**	15,844

Q3 Average Fuel Costs

US dollars	2019	2018
Dollars per Megawatt hour ("MWh")	**$ 28**	$ 31

YTD Average Fuel Costs

US dollars	2019	2018
Dollars per MWh	**$ 27**	$ 30

Average fuel cost per MWh decreased in Q3 2019 and year-to-date, compared to the same periods in 2018, primarily due to increased use of lower-cost natural gas and lower-cost solar generation.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 296**	$ 310	**$ 1,066**	$ 1,055
Regulated fuel for generation and purchased power (1)	**147**	148	**480**	460
Income from equity investments	**20**	21	**68**	71
Contribution to consolidated net income	**$ 33**	$ 36	**$ 171**	$ 174
Contribution to consolidated earnings per common share – basic	**$ 0.14**	$ 0.15	**$ 0.72**	$ 0.75
EBITDA	**$ 117**	$ 125	**$ 441**	$ 444

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Condensed 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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
NSPI	**$ 13**	$ 15	**$ 103**	$ 103
Equity investment in NSPML	**9**	10	**35**	40
Equity investment in LIL	**11**	11	**33**	31
Contribution to consolidated net income	**$ 33**	$ 36	**$ 171**	$ 174

Net Income

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2018	**$ 36**	**$ 174**
(Decreased) increased operating revenues - see Operating Revenues – Regulated Electric below	(14)	11
Decreased (increased) fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	1	(20)
Decreased FAM and fixed cost deferrals due to decreased excess non-fuel revenues in the quarter and increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment in both periods	28	22
Increased OM&G expenses primarily due to higher storm costs mainly due to post-tropical storm Dorian and higher costs for vegetation management	(26)	(28)
Increased depreciation and amortization due to increased property, plant and equipment	(2)	(8)
Decrease in income from equity investments	(1)	(3)
Decreased other expenses, net primarily due to lower non-current service pension costs	5	16
Increased interest expense, net primarily due to increased long-term debt outstanding	(2)	(5)
Decreased income taxes primarily due to changes in federal tax legislation allowing for accelerated deduction of eligible property, plant and equipment, decreased non-deductible pension expense, tax benefits of capital investment related to Dorian and decreased income before provision for income taxes. These decreases were partially offset by lower tax deductions in excess of accounting depreciation related to property, plant and equipment	9	13
Other	(1)	(1)
Contribution to consolidated net income – 2019	**$ 33**	**$ 171**

Canadian Electric Utilities' contribution to consolidated net income decreased in Q3 2019 due to lower contribution from NSPI. NSPI's decrease was primarily due to decreased sales volume partially offset by lower income taxes and lower non-current pension costs. Canadian Electric Utilities' year-to-date contribution was consistent with the same period in 2018.

Increased OM&G expenses at NSPI, related to Dorian storm restoration costs, had no overall impact on NSPI's earnings in the quarter or year-to-date, as NSPI's increased storm costs were absorbed by some of the excess non-fuel revenues that were recorded to date in 2019. Any excess non-fuel revenues that are available at the end of the fiscal year will be returned to customers through the FAM.

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

NSPI

Operating Revenues – Regulated Electric

Operating revenues decreased $14 million to $296 million in Q3 2019, compared to $310 million in Q3 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. Year-to-date operating revenues increased $11 million to $1,066 million compared to $1,055 million for the same period in 2018 primarily due to increased sales volume due to weather, increased fuel-related electricity pricing in 2019 and increased residential class sales volume. This was partially offset by decreased industrial and commercial class sales volume and the impact of the Maritime Link assessment.

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

Q3 Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**135**	$	139
Commercial		**91**		95
Industrial		**52**		60
Other		**11**		9
Total	**$**	**289**	$	303

YTD Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**552**	$	532
Commercial		**298**		298
Industrial		**160**		171
Other		**35**		33
Total	**$**	**1,045**	$	1,034

Q3 Electric Sales Volumes
GWh

	2019	2018
Residential	**810**	830
Commercial	**707**	739
Industrial	**629**	674
Other	**72**	63
Total	**2,218**	2,306

YTD Electric Sales Volumes
GWh

	2019	2018
Residential	**3,454**	3,322
Commercial	**2,305**	2,303
Industrial	**1,817**	1,942
Other	**272**	247
Total	**7,848**	7,814

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power was consistent quarter-over-quarter. Year-to-date regulated fuel for generation and purchased power increased $20 million to $480 million compared to $460 million in the same period in 2018. The increase was primarily due to increased commodity prices, partially offset by change in generation mix.

Q3 Production Volumes
GWh

	2019	2018
Coal	**918**	962
Natural gas	**451**	514
Oil and petcoke	**204**	238
Purchased power – other	**277**	217
Total non-renewables	**1,850**	1,931
Wind and hydro	**202**	150
Purchased power – Independent Power Producers ("IPP")	**195**	225
Purchased power – Community Feed-in Tariff program ("COMFIT")	**96**	101
Biomass	**14**	47
Total renewables	**507**	523
Total production volumes	**2,357**	2,454

YTD Production Volumes
GWh

	2019	2018
Coal	**3,551**	3,464
Natural gas	**1,047**	1,152
Oil and petcoke	**832**	992
Purchased power – other	**647**	365
Total non-renewables	**6,077**	5,973
Wind and hydro	**983**	884
Purchased power – IPP	**831**	906
Purchased power – COMFIT	**389**	400
Biomass	**59**	129
Total renewables	**2,262**	2,319
Total production volumes	**8,339**	8,292

Q3 Average Fuel Costs

	2019	2018
Dollars per MWh	**62**	60

YTD Average Fuel Costs

	2019	2018
Dollars per MWh	**58**	55

Average fuel cost per MWh increased in Q3 2019 and year-to-date, compared to the same periods in 2018, primarily due to increased commodity pricing and the timing of the payments of the Maritime Link assessment. These increases were partially offset by a change in generation mix.

NSPI’s FAM regulatory liability balance decreased $20 million from $161 million at December 31, 2018 to $141 million at September 30, 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.

ENL

Income from Equity Investments in NSPML and LIL

Overall income from equity investments for both Q3 2019 and year-to-date were consistent with the same periods in 2018. Lower income from NSPML in both periods was due to timing of operational costs and lower interest revenues. Year-to-date, this decrease was partially offset by 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.

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 late 2019, 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 September 30 **2019**	 2018	Nine months ended September 30 **2019**	 2018
Operating revenues – regulated electric	**$ 144**	$ 157	**$ 421**	$ 434
Regulated fuel for generation and purchased power (1)	**55**	63	**158**	170
Adjusted contribution to consolidated net income	**$ 18**	$ 23	**$ 47**	$ 49
Adjusted contribution to consolidated net income – CAD	**$ 23**	$ 31	**$ 62**	$ 64
After-tax equity securities mark-to-market gain (loss)	**-**	1	**2**	(1)
Contribution to consolidated net income	**$ 18**	$ 24	**$ 49**	$ 48
Contribution to consolidated net income – CAD	**$ 23**	$ 31	**$ 64**	$ 62
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$ 0.10**	$ 0.13	**$ 0.26**	$ 0.28
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.10**	$ 0.13	**$ 0.27**	$ 0.27
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.33**	$ 1.31	**$ 1.33**	$ 1.29
Adjusted EBITDA	**$ 52**	$ 60	**$ 149**	$ 153
Adjusted EBITDA – CAD	**$ 67**	$ 78	**$ 197**	$ 197

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

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

For the millions of US dollars	Three months ended September 30 **2019**	 2018	Nine months ended September 30 **2019**	 2018
Emera Maine	**$ 11**	$ 12	**$ 28**	$ 25
ECI	**7**	11	**19**	24
Adjusted contribution to consolidated net income	**$ 18**	$ 23	**$ 47**	$ 49

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2018	**$ 24**	**$ 48**
Decreased operating revenues - see Operating Revenues - Regulated Electric below (1)	(7)	(7)
Decreased regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below (1)	5	9
Decreased OM&G, primarily due to higher capitalized overheads as a result of higher capital spending at Emera Maine (1)	-	3
Decreased earnings at GBPC due to Hurricane Dorian	(6)	(6)
Other	2	2
Contribution to consolidated net income – 2019	**$ 18**	**$ 49**

(1) Excludes the impact of Hurricane Dorian at GBPC

Excluding the change in mark-to-market, Other Electric Utilities CAD contribution to consolidated net income decreased $8 million in Q3 2019, compared to Q3 2018. Year-to-date, the CAD contribution decreased $2 million compared to 2018. ECI's contribution decreased in both periods due to lower earnings in GBPC as a result of the impact of Hurricane Dorian in Q3 2019, partially offset by higher sales volumes at Domlec due to the completion of hurricane restoration in 2018. Emera Maine's contribution increased year-to-date due to higher capitalized overheads.

The foreign exchange rate had minimal impact for the three months ended September 30, 2019 and year-to-date increased CAD earnings by $2 million.

Operating Revenues – Regulated Electric

Operating revenues decreased $13 million to $144 million in Q3 2019, compared to $157 million in Q3 2018. Year-to-date revenues decreased $13 million to $421 million compared to $434 million in the same period in 2018. The decreases in both periods were due to lower sales at GBPC as a result of the impact of Hurricane Dorian, lower fuel costs at ECI and lower load at Emera Maine driven by unfavourable weather in Q3 2019. These decreases were partially offset by increased sales volumes at Domlec reflecting the completion of hurricane restoration in 2018. The year-to-date decrease was also due to lower stranded cost rates, unfavourable transmission revenue adjustments and lower transmission pool revenue as a result of lower rates at Emera Maine.

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

Q3 Electric Revenues
millions of USD

		2019		2018
Residential	**$**	**53**	$	55
Commercial		**64**		75
Industrial		**8**		9
Other (1)		**19**		18
Total	**$**	**144**	$	157

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

YTD Electric Revenues
millions of USD

		2019		2018
Residential	**$**	**153**	$	150
Commercial		**193**		202
Industrial		**25**		26
Other (1)		**50**		56
Total	**$**	**421**	$	434

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

Q3 Electric Sales Volumes

GWh	2019	2018
Residential	**313**	327
Commercial	**381**	398
Industrial	**124**	123
Other	**5**	7
Total	**823**	855

YTD Electric Sales Volumes

GWh	2019	2018
Residential	**951**	942
Commercial	**1,116**	1,139
Industrial	**344**	328
Other	**19**	20
Total	**2,430**	2,429

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $8 million to $55 million in Q3 2019, compared to $63 million in Q3 2018. Year-to-date, regulated fuel for generation and purchased power decreased $12 million to $158 million compared to $170 million in the same period in 2018. The decreases in both periods were due to lower oil prices at ECI and lower generation at GBPC as a result of the impact of Hurricane Dorian. The year-to-date decrease was also due to the expiration of a major purchased power contract at Emera Maine, partially offset by increased volumes at Domlec.

Q3 Production Volumes
GWh

	2019	2018
Oil	**344**	355
Hydro	**5**	7
Solar	**5**	5
Purchased power	**9**	7
Total	**363**	374

YTD Production Volumes
GWh

	2019	2018
Oil	**1,006**	995
Hydro	**15**	17
Solar	**14**	13
Purchased power	**25**	19
Total	**1,060**	1,044

Q3 Average Fuel Costs

US dollars	2019	2018
Dollars per MWh	**124**	142

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

YTD Average Fuel Costs

US dollars	2019	2018
Dollars per MWh	**121**	132

Average fuel cost per MWh decreased in Q3 2019 and year-to-date, compared to the same periods in 2018, due to lower oil prices.

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 September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Operating revenues – regulated gas (1)	**$ 156**	$ 162	**$ 604**	$ 602
Operating revenues – non-regulated	**3**	3	**9**	10
Total operating revenue	**$ 159**	$ 165	**$ 613**	$ 612
Regulated cost of natural gas	**40**	49	**188**	209
Income from equity investments	**4**	4	**14**	13
Contribution to consolidated net income	**$ 20**	$ 13	**$ 102**	$ 72
Contribution to consolidated net income – CAD	**$ 25**	$ 15	**$ 132**	$ 93
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.10**	$ 0.06	**$ 0.55**	$ 0.40
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.34**	$ 1.29	**$ 1.33**	$ 1.26
EBITDA	**$ 51**	$ 61	**$ 227**	$ 214
EBITDA – CAD	**$ 66**	$ 78	**$ 299**	$ 274

(1) Operating revenues – regulated gas includes $13 million of finance income from Brunswick Pipeline (2018 - $11 million) for the three months ended September 30, 2019 and $34 million (2018 - $31 million) for the nine months ended September 30, 2019, however, it is excluded from the gas revenues analysis below.

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

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
PGS	**$ 10**	$ 9	**$ 42**	$ 36
NMGC	**(1)**	(5)	**31**	10
Other	**11**	9	**29**	26
Contribution to consolidated net income	**$ 20**	$ 13	**$ 102**	$ 72

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2018	**$ 13**	**$ 72**
Decreased gas operating revenues net of recognition of tax reform benefits - see Operating Revenues - Regulated Gas below	(6)	(7)
Decreased cost of natural gas sold - see Regulated Cost of Natural Gas below	9	21
Increased OM&G expenses quarter-over-quarter due to PGS tax reform settlement. In Q3 2018, PGS reversed deferred tax reform related OM&G expense recorded through Q2 2018 and recorded amortization expense related to the regulatory asset associated with manufactured gas plant ("MGP") environmental remediation costs. Year-over-year, OM&G expense also increased due to higher insurance and benefits expense in PGS and NMGC in 2019	(12)	(8)
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	8	14
Recognition of tax benefit related to change in treatment of NOL carryforwards at NMGC	5	5
Recognition of tax reform benefits, net of tax, from January 2018 through June 2019 in NMGC, of which $6 million relates to 2018	-	9
Other	3	(4)
Contribution to consolidated net income – 2019	**$ 20**	**$ 102**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $10 million compared to Q3 2018. Year-to-date, Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $39 million compared to 2018. NMGC's recognition of the tax benefit related to the change in treatment of NOL carryforwards resulted in a $7 million ($5 million USD) increase in net income for Q3 2019 and year-to-date. The year-to-date increase was also due to NMGC's recognition of tax reform benefits from January 1, 2018 to June 30, 2019, which resulted in a $12 million ($9 million USD) increase in Q2 2019; customer growth at PGS; favourable weather in New Mexico; and lower depreciation and amortization in PGS.

The foreign exchange rate had minimal impact for the three months ended September 30, 2019 and year-to-date 2019 increased CAD earnings by $4 million.

Operating Revenues – Regulated Gas

Beginning January 1, 2019, as approved by the FPSC, base rates at PGS were lowered by $12 million USD annually to reflect the impact of tax reform, resulting in a $3 million USD decrease in revenue in Q3 2019 and a $8 million decrease year-to-date.

Gas Utilities and Infrastructure's operating revenues decreased $6 million to $156 million in Q3 2019, compared to $162 million in Q3 2018. The decrease was the result of lower off-system sales at PGS and lower base rates at PGS reflecting the impact of tax reform, partially offset by customer growth in PGS and higher clause revenues in New Mexico.

Year-to-date operating revenues increased $2 million to $604 million compared to $602 million in the same period in 2018. The increase was the result of customer growth in PGS, favourable weather in New Mexico and the NMPRC's approval of NMGC retaining tax reform benefits from January 1, 2018 to June 30, 2019. These increases were offset by unfavourable weather, lower off-system sales and lower base rates at PGS reflecting the impact of tax reform, and lower clause-related revenues at PGS and New Mexico due lower cost of natural gas sold.

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

Q3 Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**58**	$	57
Commercial		**43**		42
Industrial (1)		**9**		10
Other (2)		**33**		42
Total (3)	**$**	**143**	$	151

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

YTD Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**270**	$	265
Commercial		**162**		165
Industrial (1)		**28**		28
Other (2)		**110**		113
Total (3)	**$**	**570**	$	571

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $34 million of finance income from Brunswick Pipeline (2018 – $31 million).

Q3 Gas Volumes
Therms (millions)

	2019	2018
Residential	**35**	34
Commercial	**165**	156
Industrial	**386**	367
Other	**93**	86
Total	**679**	643

YTD Gas Volumes
Therms (millions)

	2019	2018
Residential	**275**	248
Commercial	**605**	581
Industrial	**1,106**	999
Other	**229**	197
Total	**2,215**	2,025

Regulated Cost of Natural Gas

Regulated cost of natural gas decreased $9 million to $40 million in Q3 2019, compared to $49 million in Q3 2018. Year-to-date, regulated cost of natural gas decreased $21 million to $188 million in Q3 2019, compared to $209 million in the same period in 2018. The decrease in both periods was due to lower commodity costs in PGS, lower PGS off-system volume sales and lower commodity costs in New Mexico year-to-date.

Gas sales by type are summarized in the following table:

Q3 Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**110**	127
Transportation	**569**	516
Total	**679**	643

YTD Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**519**	503
Transportation	**1,696**	1,522
Total	**2,215**	2,025

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2019**	2018	Nine months ended September 30 **2019**	2018
Marketing and trading margin (1) (2)	**$ (23)**	$ 6	**$ 3**	$ 73
Electricity and capacity sales (3) (4)	**-**	106	**116**	313
Other non-regulated operating revenue	**12**	13	**30**	35
Total operating revenues – non-regulated	**$ (11)**	$ 125	**$ 149**	$ 421
Intercompany revenue (5)	**4**	10	**17**	29
Non-regulated fuel for generation and purchased power (4)(6)	**-**	54	**66**	170
Operating, maintenance and general	**29**	40	**103**	130
Depreciation and amortization	**2**	14	**8**	40
Income from equity investments	**8**	10	**25**	24
Interest expense, net	**81**	92	**256**	271
Adjusted contribution to consolidated net income (loss)	**$ (112)**	$ (34)	**$ (228)**	$ (125)
After-tax derivative mark-to-market gain (loss)	**$ (67)**	$ (73)	**$ (8)**	$ (23)
Contribution to consolidated net income (loss)	**$ (179)**	$ (107)	**$ (236)**	$ (148)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.46)**	$ (0.15)	**$ (0.95)**	$ (0.54)
Contribution to consolidated earnings per common share – basic	**$ (0.74)**	$ (0.46)	**$ (0.99)**	$ (0.64)
Adjusted EBITDA	**$ (42)**	$ 45	**$ 7**	$ 148

(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 loss of $102 million in Q3 2019 (2018 - $108 million loss) and a loss of $19 million year-to-date (2018 – $71 million loss).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market loss of nil in Q3 2019 (2018 - $3 million loss) and year-to-date gain of $2 million (2018 – $28 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 gain of $2 million in Q3 2019 (2018 - $2 million gain) and year-to-date $1 million loss (2018 – $5 million gain).

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

For the millions of Canadian dollars	Three months ended September 30 **2019**	2018	Nine months ended September 30 **2019**	2018
Emera Energy	**$ (14)**	$ 19	**$ 19**	$ 76
Corporate	**(99)**	(53)	**(247)**	(202)
Other	**1**	-	**-**	1
Adjusted contribution to consolidated net income (loss)	**$ (112)**	$ (34)	**$ (228)**	$ (125)

Net Income

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income (loss) – 2018	**$ (107)**	**$ (148)**
Decreased marketing and trading margin - see Emera Energy below	(29)	(70)
Impact of sale of NEGG and Bayside Power, net of tax	(18)	(22)
Transaction costs related to the pending sale of Emera Maine	(2)	(6)
Decreased income tax recovery due to 2018 recognition of Florida state tax apportionment benefit	(23)	(23)
Increased income tax recovery primarily due to increased losses before provision for income taxes	8	19
Corporate share of the unrecoverable loss on GBPC facilities	(9)	(9)
Increased preferred stock dividends due to the issuance of preferred shares in Q2 2018	(1)	(9)
Gain on sale of property in Florida, pre-tax	-	14
Decreased mark-to-market loss, 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 decreased mark-to-market loss, 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	6	15
Other	(4)	3
Contribution to consolidated net income (loss) – 2019	**$ (179)**	**$ (236)**

Excluding the change in mark-to-market, Other's contribution to consolidated net income decreased by $78 million for the quarter and $103 million year-to-date compared to the same periods in 2018. In both periods, the decrease was due to lower marketing and trading margin, the impact of the sale of NEGG and Bayside Power, the corporate share of the unrecoverable loss on GBPC's facilities, decreased income tax recovery and higher preferred stock dividends. The year-to-date decrease was partially offset by the gain on sale of property in Florida.

Emera Energy

Marketing and trading margin decreased $29 million to $(23) million in Q3 2019, compared to $6 million in Q3 2018. Year-to-date margin decreased $70 million to $3 million in 2019, compared to $73 million for the same period 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.

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, including 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 $3.1 billion of credit. Refer to the "Debt Management" section for additional information regarding the credit facilities.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 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 change in working capital		**1,182**		1,237		(55)
Change in working capital		**128**		156		(28)
Operating activities		**1,310**		1,393		(83)
Investing activities		**(786)**		(1,565)		779
Financing activities		**(546)**		121		(667)
Effect of exchange rate changes on cash, cash equivalents, restricted cash and cash included in assets held for sale		**(13)**		11		(24)
Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period	**$**	**337**	$	463	$	(126)

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $83 million to $1,310 million for the nine months ended September 30, 2019, compared to $1,393 million for the same period in 2018.

Cash from operations before changes in working capital decreased $55 million. The decrease was due to lower marketing and trading margin at EES and lower earnings from EEG as a result of the sale of NEGG and Bayside. These were partially offset by lower under-recovery from customers on clause related costs at Tampa Electric.

Changes in working capital decreased operating cash flows by $28 million. The decrease was due to unfavourable changes in cash collateral at NSPI and Emera Energy. These were partially offset by a refund of $146 million ($109 million USD) of alternative minimum tax credit carryforwards in April 2019 and favourable changes in accounts payable at Tampa Electric.

Cash Flow used in Investing Activities

Net cash used in investing activities decreased $779 million to $786 million for the nine months ended September 30, 2019, compared to $1,565 million for the same period in 2018. In 2019, Emera received proceeds of $866 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 nine months ended September 30, 2019, including AFUDC, were $1,662 million compared to $1,556 million for the same period in 2018. Details of the 2019 capital spend by segment are shown below:

- $919 million - Florida Electric Utility (2018 – $915 million);
- $263 million - Canadian Electric Utilities (2018 – $251 million);
- $127 million - Other Electric Utilities (2018 – $120 million);
- $295 million - Gas Utilities and Infrastructure (2018 – $220 million); and
- $58 million - Other (2018 – $50 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $667 million to $546 million for the nine months ended September 30, 2019, compared to net cash provided by financing activities of $121 million for the same period in 2018. The increase was due to repayment of corporate long-term debt, net repayment of committed credit facilities at Tampa Electric, a 2018 preferred share issuance and repayments at NSPI. These were partially offset by proceeds from the issuance of long-term debt at NSPI in 2019 and the 2018 repayment of debt at TECO Finance.

Contractual Obligations

As at September 30, 2019, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt principal (1)	$ 249	$ 548	$ 1,686	$ 547	$ 1,168	$ 10,800	$ 14,998
Interest payment obligations (2)(3)	297	664	618	581	554	7,488	10,202
Purchased power (4)(5)	63	208	231	245	249	2,496	3,492
Transportation (6)	140	426	346	307	267	2,955	4,441
Pension and post-retirement obligations (7)(8)	9	34	34	35	36	1,030	1,178
Capital projects (9)	305	292	37	11	1	-	646
Fuel, gas supply and storage	196	440	104	4	1	-	745
Asset retirement obligations	2	9	44	1	1	362	419
Long-term service agreements (10)(11)	10	43	30	29	21	124	257
Equity investment commitments (12)	-	-	190	-	-	-	190
Leases and other (13)	10	16	17	16	10	126	195
Demand side management	12	31	37	39	-	-	119
Long-term payable	1	5	5	5	5	-	21
Convertible debentures	-	-	-	-	-	2	2
	$ 1,294	$ 2,716	$ 3,379	$ 1,820	$ 2,313	$ 25,383	$ 36,905

As noted below, Contractual Obligations at September 30, 2019 include contractual commitments 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 $515 million related to Emera Maine ($40 million in 2020; $119 million in 2022; $79 million in 2023 and $277 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 September 30, 2019, including any expected required payment under associated swap agreements.
(3) Includes $345 million related to Emera Maine ($5 million in 2019; $20 million in 2020; $18 million in 2021; $13 million in 2022; $12 million in 2023 and $277 million thereafter).
(4) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(5) Includes $551 million related to Emera Maine ($4 million in 2019; $14 million in 2020; $25 million in 2021; $32 million in 2022; $32 million in 2023 and $444 million thereafter).
(6) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(7) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2018. Credited service and earnings are assumed to be crystallized as at December 31, 2018. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over (50 for TECO Energy) as at December 31, 2018 to be eligible. As the defined benefit pension plans currently undergo regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.
(8) Includes $88 million related to Emera Maine ($1 million in 2019; $7 million in 2020; $7 million in 2021; $7 million in 2022; $7 million in 2023 and $59 million thereafter).
(9) Includes $356 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 $26 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($4 million in 2019; $14 million in 2020; $4 million in 2021; $2 million in 2022; and $2 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 is $111 million, which is currently included in NSPI rates. This payment is subject to a $10 million holdback. On June 14, 2019, NSPML filed an interim assessment application requesting recovery of 2020 costs of approximately $145 million, subject to a $10 million holdback, with a decision expected in Q4 2019. NSPI has included the difference of $34 million in its proposed fuel stability plan filed with the UARB. After 2020, the timing and amounts payable to NSPML will be subject to 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 Nova Scotia Block, and continuing for 50 years. As transmission rights are contracted, Emera includes the obligations within "Leases and other" in the above table.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.1 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	$ 432	$ 468
TECO Finance, Inc. – in USD – Operating credit facilities	March 2020 - March 2022	900	500	400
NSPI – Operating credit facility	October 2023	600	270	330
TEC - in USD - credit facilities (1)	March 2021 - March 2022	475	137	338
NMGC – in USD – Operating credit facility	March 2022	125	73	52
Emera Maine – in USD – Operating credit facility	February 2023	80	62	18
Other - in USD - Operating credit facility	Various	32	11	21

(1) This facility is available for use by Tampa Electric and PGS. At September 30, 2019, Tampa Electric had utilized $93 million USD and PGS had utilized $44 million USD of the facility.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at September 30, 2019.

Recent financing activities for Emera and its subsidiaries are discussed below by segment:

Florida Electric Utilities

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 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 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

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

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.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2018 audited annual consolidated financial statements, with updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $54 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 Reinsurance Limited has issued a standby letter of credit to secure obligations under reinsurance agreements. The expiry date of this letter of credit was extended to May 2020. This letter of credit is renewed annually. The amount committed as of September 30, 2019 was $4 million USD (December 31, 2018 - $6 million USD).

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2020. The amount committed as at September 30, 2019 was $52 million (December 31, 2018 - $49 million).

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 Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $26 million for the three months ended September 30, 2019 (2018 - $25 million) and $80 million for the nine months ended September 30, 2019 (2018 - $76 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 Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $16 million for the three months ended September 30, 2019 (2018 - $6 million) and $50 million for the nine months ended September 30, 2019 (2018 - $22 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2019 and at December 31, 2018.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2018 annual MD&A, with the exception of the following update to labour risk:

Approximately 30 per cent of Emera's employees are within the NSPI labour force and approximately 50 per cent of those employees are represented by the International Brotherhood of Electrical Workers Local 1928 ("IBEW"). NSPI and the IBEW reached a new collective agreement, ratified on August 23, 2019, for a four-year term ending on March 31, 2023. The previous collective agreement governing these employees expired on March 31, 2019.

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	**September 30 2019**	December 31 2018
Derivative instrument liabilities (current and long-term liabilities)	**$ (1)**	$ (5)
Net derivative instrument assets (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	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Operating revenues – regulated	**$ (1)**	$ 1	**$ (3)**	$ 5
Non-regulated fuel for generation and purchased power	**-**	(1)	**-**	2
Effective net gains (losses)	**$ (1)**	$ -	**$ (3)**	$ 7

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	**September 30 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 44**	$ 104
Regulatory assets (current and other assets)	**65**	6
Derivative instrument liabilities (current and long-term liabilities)	**(65)**	(6)
Regulatory liabilities (current and long-term liabilities)	**(55)**	(115)
Net asset (liability)	**$ (11)**	$ (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	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Regulated fuel for generation and purchased power (1)	**$ -**	$ 6	**$ 7**	$ 11
Net gains (losses)	**$ -**	$ 6	**$ 7**	$ 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	**September 30 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 52**	$ 62
Derivative instrument liabilities (current and long-term liabilities)	**(310)**	(354)
Net derivative instrument assets (liabilities)	**$ (258)**	$ (292)

HFT 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	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Operating revenue - non-regulated	**$ (69)**	$ (105)	**$ 180**	$ 44
Non-regulated fuel for purchased power	**1**	2	**(4)**	2
Net gains (losses)	**$ (68)**	$ (103)	**$ 176**	$ 46

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	**September 30 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 33**	$ 1
Net derivative instrument assets (liabilities)	**$ 33**	$ 1

Other Derivatives Recognized in Net Income

For the three months ended September 30, 2019, the Company had unrealized gains on equity derivatives of $11 million (2018 – nil) and $34 million for the nine months ended September 30, 2019 (2018- nil) recorded in Operating, maintenance and general expense in the Condensed Consolidated Statements of Income.

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 of the Company's DC&P and ICFR as at September 30, 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 September 30, 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 USGAAP 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. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in the Company's 2018 annual MD&A.

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 condensed 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 three and nine months ended September 30, 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 16 of the 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 condensed 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 condensed 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 ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the Company's 2018 audited consolidated financial statements, with updates noted below.

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. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019, and will be applied using a modified retrospective approach. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018. The Company will not early adopt the standard. The Company does not expect a material impact on its consolidated financial statements as a result of adoption of the standard.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q3 2019**	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Operating revenues	**$ 1,299**	$ 1,378	$ 1,818	$ 1,799	$ 1,495	$ 1,423	$ 1,807	$ 1,473
Net income (loss) attributable to common shareholders	**55**	103	312	231	118	90	271	(228)
Adjusted net income attributable to common shareholders	**122**	130	224	167	191	111	202	137
Earnings per common share – basic	**0.23**	0.43	1.32	0.98	0.51	0.38	1.17	(1.06)
Earnings per common share – diluted	**0.23**	0.43	1.32	0.98	0.50	0.38	1.17	(1.06)
Adjusted earnings per common share – basic	**0.51**	0.54	0.95	0.71	0.82	0.48	0.87	0.64

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.