Management's Discussion & Analysis

As at August 9, 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 second quarter and year-to-date of 2019 relative to the same periods in 2018; and its financial position as at June 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 six months ended June 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, LLC; 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 six months ended June 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")	National Energy Board ("NEB")
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")	NEB 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 $6.5 billion capital investment plan over the 2019-to-2021 period, including investing $1.4 billion ($1 billion USD) in Florida for the completion of Tampa Electric's 600 megawatts ("MW") of solar generation and the modernization of the Big Bend Power Station. This planned capital investment is being funded primarily through internally generated cash flows, debt raised at the operating company level and select asset sales. Equity capital markets, including the issuance of common and preferred equity and the dividend reinvestment plan will continue to support the Company's future capital investments. Maintaining investment-grade credit ratings is a key priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2021. 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 but not 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. Customers are looking for more choice, control and reliability. 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Net income attributable to common shareholders	**$ 103**	$ 90	**$ 415**	$ 361
After-tax mark-to-market gain (loss)	**$ (27)**	$ (21)	**$ 61**	$ 48
Adjusted net income attributable to common shareholders	**$ 130**	$ 111	**$ 354**	$ 313
Earnings per common share – basic	**$ 0.43**	$ 0.38	**$ 1.75**	$ 1.56
Adjusted earnings per common share – basic	**$ 0.54**	$ 0.48	**$ 1.49**	$ 1.35

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 adjustments.

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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Net income (1)	**$ 116**	$ 97	**$ 440**	$ 375
Interest expense, net	**185**	176	**374**	351
Income tax expense (recovery)	**(15)**	(3)	**67**	62
Depreciation and amortization	**228**	228	**452**	451
EBITDA	**514**	498	**1,333**	1,239
Mark-to-market gain (loss), excluding income tax and interest	**(41)**	(31)	**85**	69
Adjusted EBITDA	**$ 555**	$ 529	**$ 1,248**	$ 1,170

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

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

After-tax mark-to-market losses increased $6 million to $27 million in Q2 2019, compared to $21 million in Q2 2018. This increase, mainly related to Emera Energy, was due to higher amortization of gas transportation assets in 2019, partially offset by changes in existing positions on gas contracts in Q2 2019. Year-to-date, after-tax mark-to-market gains increased $13 million to $61 million in 2019, compared to $48 million for the same period in 2018. This increase, mainly related to Emera Energy, was due to a larger reversal of mark-to-market losses in 2019, compared to 2018, and changes in existing positions on gas contracts in 2019, partially offset by higher amortization of gas transportation assets in 2019.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended June 30		Six months ended June 30	
Adjusted net income	**2019**	2018	**2019**	2018
Florida Electric Utility	**$ 125**	$ 95	**$ 186**	$ 155
Canadian Electric Utilities	**42**	48	**138**	138
Other Electric Utilities	**23**	18	**39**	33
Gas Utilities and Infrastructure	**40**	25	**107**	78
Other	**(100)**	(75)	**(116)**	(91)
Adjusted net income attributable to common shareholders	**$ 130**	$ 111	**$ 354**	$ 313
After-tax mark-to-market gain (loss)	**(27)**	(21)	**61**	48
Net income attributable to common shareholders	**$ 103**	$ 90	**$ 415**	$ 361

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

For the millions of Canadian dollars	Three months ended June 30	Six months ended June 30
Adjusted net income – 2018	**$ 111**	**$ 313**
Florida Electric Utility	30	31
Recognition of tax reform benefits from January 2018 through June 2019 in NMGC, of which $8 million relates to 2018	12	12
Gas Utilities and Infrastructure	3	17
Gain on sale of property in Florida	-	10
Other Electric Utilities	5	6
Canadian Electric Utilities	(6)	-
Emera Energy	(21)	(24)
Other variances	(4)	(11)
Adjusted net income – 2019	**$ 130**	**$ 354**

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

For the millions of Canadian dollars	Six months ended June 30	
	2019	2018
Operating cash flow before changes in working capital	**$ 775**	$ 767
Change in working capital	**32**	97
Operating cash flow	**$ 807**	$ 864
Investing cash flow	**$ (264)**	$ (984)
Financing cash flow	**$ (515)**	$ 1

As at millions of Canadian dollars	**June 30 2019**	December 31 2018
Total assets	**$ 30,860**	$ 32,314
Total long-term debt (including current portion)	**$ 13,912**	$ 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 June 30 2019	2018	Variance	Six months ended June 30 2019	2018	Variance
Operating revenues	$	**1,378**	$ 1,423	$ (45)	**$ 3,196**	$ 3,230	$ (34)
Operating expenses		**1,138**	1,184	46	**2,414**	2,501	87
Income from operations		**240**	239	1	**782**	729	53
Income from equity investments		**40**	43	(3)	**80**	80	-
Other income (expenses), net		**6**	(12)	18	**19**	(21)	40
Interest expense, net		**185**	176	(9)	**374**	351	(23)
Income tax expense (recovery)		**(15)**	(3)	12	**67**	62	(5)
Net income		**116**	97	19	**440**	375	65
Net income attributable to common shareholders		**103**	90	13	**415**	361	54
After-tax mark-to-market gain (loss)		**(27)**	(21)	(6)	**61**	48	13
Adjusted net income attributable to common shareholders	$	**130**	$ 111	$ 19	**$ 354**	$ 313	$ 41
Earnings per common share – basic	$	**0.43**	$ 0.38	$ 0.05	**$ 1.75**	$ 1.56	$ 0.19
Earnings per common share – diluted	$	**0.43**	$ 0.38	$ 0.05	**$ 1.74**	$ 1.55	$ 0.19
Adjusted earnings per common share – basic	$	**0.54**	$ 0.48	$ 0.06	**$ 1.49**	$ 1.35	$ 0.14
Dividends per common share declared	$	**0.5875**	$ 0.5650	$ 0.0225	**$ 1.1750**	$ 1.1300	$ 0.0450
Adjusted EBITDA	$	**555**	$ 529	$ 26	**$ 1,248**	$ 1,170	$ 78

Operating Revenues

For the second quarter of 2019, operating revenues decreased $45 million compared to the second quarter in 2018. Absent increased mark-to-market losses of $6 million, operating revenues decreased $39 million due to:

- $85 million decrease in the Other segment due to the sale of the New England Gas Generating Facilities ("NEGG");
- $34 million decrease at Florida Electric Utility due to lower base rates as a result of US tax reform; and
- $26 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and higher fixed cost commitments for transportation and storage assets.

These impacts were partially offset by increases of:

- $72 million at Florida Electric Utility as a result of higher base revenues related to in-service of solar generation projects, customer growth, favourable weather, higher clause revenues and the impact of a weaker Canadian dollar; and
- $21 million at Gas Utilities and Infrastructure a result of NMGC's recognition of tax reform benefits from January 1, 2018 to June 30, 2019, favourable weather in New Mexico and customer growth at PGS. These increases were offset by lower base rates at PGS to reflect the impact of US tax reform and less favourable weather.

Year-to-date in 2019, operating revenues decreased $34 million compared to the same period in 2018. Absent increased mark-to-market gains of $17 million, operating revenues decreased by $51 million due to:

- $91 million decrease in the Other segment due to the sale of NEGG;
- $63 million decrease at Florida Electric Utility due to lower base rates as a result of US tax reform; and
- $41 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and increased fixed cost commitments for transportation and storage assets.

These impacts were partially offset by increases of:

- $66 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, higher clause revenues and customer growth;
- $37 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 and customer growth at PGS. These increases were partially offset by lower base rates at PGS to reflect the impact of tax reform tariffs, less favourable weather and lower clause-related revenues; and
- $25 million at Canadian Electric Utilities as a result of increased sales volumes at NSPI due to weather, increased fuel related pricing and load growth, partially offset by the impact of the Maritime Link assessment

Operating Expenses

For the second quarter of 2019, operating expenses decreased $46 million compared to the second quarter of 2018. Absent decreased mark-to-market gains of $4 million, operating expenses decreased $50 million due to:

- $61 million decrease in the Other segment primarily due to the sale of NEGG and the Bayside power plant located in New Brunswick ("Bayside"); and
- $39 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.

This was partially offset by an increase of:

- $38 million at Florida Electric Utility due to increased fuel costs, higher depreciation expense and a weaker Canadian dollar; and
- $23 million at Canadian Electric Utilities primarily due to the timing of regulatory deferrals and increased OM&G expenses.

Year-to-date, operating expenses decreased $87 million compared to the same period of 2018. Absent increased mark-to-market losses of $6 million, operating expenses decreased $81 million due to:

- $85 million decrease in the Other segment as a result of the sale of NEGG and Bayside; and
- $60 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 increased fuel for generation and purchased power at NSPI as a result of increased commodity prices, increased sales volumes and the impact of the Maritime Link assessment; and
- $20 million at Florida Electric Utility primarily as a result of the impact of a weaker Canadian dollar.

Other Income (Expenses), Net

The increase in other income (expenses), net for the second quarter was primarily due to lower non-current service pension costs at NSPI. Year-to-date in 2019, the increase was also due to the gain on sale of property in Florida.

Interest Expense

The increase in interest expense, net for the second quarter was primarily a result of a weaker Canadian dollar. Year-to-date in 2019, the increase was also due to higher borrowings at Florida Electric Utility and Canadian Electric Utilities.

Income Tax Expense (Recovery)

The increase in income tax recovery for the second quarter in 2019, compared to the same period in 2018 was primarily due to an increase in the proportion of income earned in lower tax rate foreign jurisdictions, increased deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities, and amortization of deferred income tax regulatory liabilities. The 2019 year-to-date increase in income tax expense was not material.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the second quarter of 2019, net income attributable to common shareholders was unfavourably impacted by the $6 million increase in after-tax mark-to-market losses primarily related to Emera Energy. Absent the unfavourable mark-to-market changes, adjusted net income attributable to common shareholders increased $19 million. The increase was due to higher contribution from Florida Electric Utility and NMGC's recognition of tax reform benefits, partially offset by decreased contributions from Emera Energy in the Other segment.

Year-to-date in 2019, net income attributable to common shareholders was favourably impacted by the $13 million increase in after-tax mark-to-market gains primarily related to Emera Energy. Absent the favourable mark-to-market changes, adjusted net income attributable to common shareholders increased $41 million. The increase was due to 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. These were partially offset by decreased contributions from Emera Energy in the Other segment.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share – basic were higher for the second quarter and year-to-date due to increased earnings as discussed above, partially offset by 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 June 30		Six months ended June 30		Year ended December 31
	2019	2018	**2019**	2018	2018
Weighted average CAD/USD	**$ 1.34**	$ 1.29	**$ 1.33**	$ 1.27	$ 1.30
Period end CAD/USD exchange rate	**$ 1.31**	$ 1.32	**$ 1.31**	$ 1.32	$ 1.36

The weakening of the CAD increased earnings by $2 million and adjusted earnings by $4 million in Q2 2019, compared to Q2 2018. The weakening of the CAD increased earnings by $14 million and adjusted earnings by $12 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Florida Electric Utility	**$ 93**	$ 73	**$ 139**	$ 121
Other Electric Utilities	**17**	14	**29**	26
Gas Utilities and Infrastructure (1)	**25**	13	**70**	49
	135	100	**238**	196
Other segment (2)	**(59)**	(32)	**(75)**	(35)
Total (3)	**$ 76**	$ 68	**$ 163**	$ 161

(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.

In Q2 2019, a law was passed in Florida establishing 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. The FPSC is expected to propose a rule to implement this clause by October 31, 2019.

On June 28, 2019, Tampa Electric filed a petition for the January 1, 2020 Solar Base Rate Adjustment ("SoBRA") representing 149 MW and $27 million USD annually in estimated revenue requirements. A decision by the FPSC regarding the tariffs on this SoBRA filing is anticipated in Q4 2019.

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 June 14, 2019, the FPSC approved Tampa Electric's settlement agreement with consumer parties regarding eligibility of 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 $1.0 billion USD (2018 - $940 million USD), including allowance for funds used during construction ("AFUDC"). Capital projects include supporting normal 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 complete 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.

On June 27, 2019, NSPI filed an application for a fuel stability plan with the UARB. If this application is approved, it will result in an annual rate increase averaging 2 per cent per year for the 2020 through 2022 period to recover fuel costs. A hearing is scheduled for October 2019 with a decision by the UARB expected 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. In March 2019, the proposed renewal of the Canada-Nova Scotia Equivalency Agreement was released for public comment and 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 that extends to 2040 recognizing equivalent outcomes between federal and provincial environmental laws and regulations.

NSPI has completed registration under the Nova Scotia Cap-and-Trade Program Regulations and received its 2019 granted emissions credits in April 2019. These 2019 credits 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 ("SO2") emissions which will lessen the reduction in the SO2 emissions for the 2020 through 2022 fuel stability period. The Regulations have been driving a steady decrease in SO2 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 SO2 emissions. NSPI has incorporated the impact of these changes into the fuel stability plan that was filed with the UARB on June 27, 2019.

NSPI continues to advance its "Coal to Clean" strategy. To date, carbon dioxide reductions of over 30 per cent from 2005 levels have been achieved, 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 over 55 per cent reductions in carbon dioxide by 2030.

In 2019, NSPI expects to invest approximately $360 million (2018 - $348 million), including AFUDC, in capital projects to support system reliability and AMI.

ENL

Equity earnings from NSPML and LIL 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. 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 $40 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 $556 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 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 regulatory approvals. 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:
    - 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 anticipated to increase over the prior year. 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. Earnings from ECI's utilities in 2019 are expected to be consistent with 2018.

In 2019, capital expenditures in the Other Electric Utilities segment are expected to be approximately $200 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 the second quarter, as discussed below, and colder weather throughout the first quarter. 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 will be 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.

In 2019, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $350 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 Q3 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 earn at the lower end of this range in 2019.

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 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 2018, and lower tax recoveries due to the change in Florida state tax apportionment factors that resulted in the remeasurement of certain deferred tax balances in 2018.

In 2019, capital expenditures in the Other segment are expected to be approximately $50 million (2018 - $75 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2018 and June 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				
Derivative instruments (current and long-term)	**(52)**	**-**	**(52)**	Decreased due to settlement of derivatives and lower commodity prices at NSPI, partially offset by the equity derivative at Emera Corporate.
Regulatory assets (current and long-term)	**(59)**	**(125)**	**66**	Increased due to derivative instruments and deferred income tax regulatory asset 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)	**(420)**	**(77)**	**(343)**	Decreased due to lower commodity prices and lower cash collateral positions at Emera Energy, refund of alternative minimum tax credit carry forwards at Corporate 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	**(102)**	**706**	**(808)**	Decreased due to completion of the sale of the NEGG facilities.
Property, plant and equipment, net of accumulated depreciation and amortization	**(1,310)**	**(1,285)**	**(25)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates, partially offset by increased additions at Tampa Electric and NSPI.
Goodwill	**(404)**	**(149)**	**(255)**	Decreased due to the effect of a stronger CAD on the translation of Emera’s foreign subsidiaries.

Liabilities and Equity				
Short-term debt and long-term debt (including current portion)	**(1,387)**	**(482)**	**(905)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and repayment of Emera US Finance LP USD note upon maturity. These were partially offset by increased borrowings in NSPI.
Accounts payable	**(350)**	**(38)**	**(312)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries, lower commodity prices at Emera Energy, lower cash collateral on derivative instruments at NSPI and timing of accounts payable payments at Tampa Electric, NSPI and NMGC.
Deferred income tax liabilities, net of deferred income tax assets	**(234)**	**(197)**	**(37)**	No significant change after removing impact of held for sale classification.
Derivative instruments (current and long-term)	**(110)**	**-**	**(110)**	Decreased due to Emera Energy's reversal of 2018 asset management agreements and change in existing positions, partially offset by new contracts at Emera Energy.
Regulatory liabilities (current and long-term)	**(304)**	**(157)**	**(147)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and deferrals related to derivative instruments at NSPI.
Pension and post-retirement liabilities	**(102)**	**(71)**	**(31)**	No significant change after removing impact of held for sale classification.
Other liabilities (current and long-term)	**26**	**(28)**	**54**	Increased due to 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	**194**	**-**	**194**	Increased due to the dividend reinvestment plan and an increase in options exercised.
Accumulated other comprehensive income	**(257)**	**-**	**(257)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Retained earnings	**137**	**-**	**137**	Increased due to net income in excess of dividends paid.

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at June 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

At-The-Market Equity Program

On July 11, 2019, Emera established an at-the-market equity program (“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 was filed on June 14, 2019 and expires on July 14, 2021.

As at August 9, 2019, the Company has not issued any shares 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 certain regulatory approvals including the approval of the MPUC. On June 25, 2019, the transaction received approval by the FERC and, on July 18, 2019, the Committee on Foreign Investment in the United States concluded its review of the transaction and found no unresolved national security concerns. The applicable provisions of the Hart-Scott-Rodino Antitrust Improvements Act have been satisfied. 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.

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
Issued for cash under Purchase Plans at market rate	2.20	106
Discount on shares purchased under Dividend Reinvestment Plan	-	(5)
Options exercised under senior management stock option plan	2.29	93
Balance, June 30, 2019	**238.61**	**$ 6,010**

As at August 6, 2019, the amount of issued and outstanding common shares was 238.7 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 June 30, 2019 was 239.2 million (2018 – 232.5 million) and for the six months ended June 30, 2019 was 237.8 million (2018 – 231.8 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 521**	$ 511	**$ 933**	$ 972
Regulated fuel for generation and purchased power	**156**	151	**271**	292
Contribution to consolidated net income	**$ 93**	$ 73	**$ 139**	$ 121
Contribution to consolidated net income – CAD	**$ 125**	$ 95	**$ 186**	$ 155
Contribution to consolidated earnings per common share – basic - CAD	**$ 0.52**	$ 0.41	**$ 0.78**	$ 0.67
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.34**	$ 1.29	**$ 1.34**	$ 1.26
EBITDA	**$ 226**	$ 193	**$ 392**	$ 353
EBITDA – CAD	**$ 301**	$ 249	**$ 522**	$ 451

Net Income

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

For the millions of US dollars	Three months ended June 30	Six months ended June 30
Contribution to consolidated net income – 2018	**$ 73**	**$ 121**
Increased (decreased) operating revenues - see Operating Revenues - Regulated Electric below	10	(39)
(Increased) decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(5)	21
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	26	50
Increased depreciation and amortization due to increased property, plant and equipment	(6)	(11)
Increased interest expense due to increased capital spending	(4)	(6)
Increased other income as the result of higher AFUDC earnings due to the Big Bend modernization, construction of solar, and AMI projects	2	4
Other	(3)	(1)
Contribution to consolidated net income – 2019	**$ 93**	**$ 139**

Florida Electric Utility’s CAD contribution to consolidated net income increased $30 million in Q2 2019, compared to Q2 2018. Year-to-date, Florida Electric Utility’s CAD contribution to consolidated net income increased $31 million in 2019. Increases in both periods were due to higher base revenues related to the in-service of solar generation projects, customer growth and higher AFUDC earnings. Higher base revenues in Q2 2019 were also due to favourable weather. These increases were partially offset by lower base rates as a result of tax reform and higher depreciation and 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 six months ended June 30, 2019 by $4 million and $7 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 $25 million decrease in revenue in Q2 2019 and a $47 million decrease year-to-date.

Electric revenues increased $10 million to $521 million in Q2 2019, compared to $511 million in Q2 2018. Year-to-date, electric revenues decreased $39 million to $933 million in 2019, compared to $972 million for the same period in 2018. The increase in Q2 2019 was due to higher base and clause revenues related to in-service of solar generation projects, customer growth and weather, partially offset by a reduction in base rates as a result of US tax reform. Year-to-date revenues decreased due to lower base rates as a result of US tax reform and lower clause revenues, 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:

Q2 Electric Revenues
millions of US dollars

		2019		2018
Residential	**$**	**261**	$	241
Commercial		**141**		140
Industrial		**42**		40
Other (1)		**77**		90
Total	**$**	**521**	$	511

(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	**$**	**467**	$	471
Commercial		**261**		272
Industrial		**76**		78
Other (1)		**129**		151
Total	**$**	**933**	$	972

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

Q2 Electric Sales Volumes
Gigawatt hours ("GWh")

	2019	2018
Residential	**2,366**	2,133
Commercial	**1,543**	1,503
Industrial	**539**	505
Other	**506**	586
Total	**4,954**	4,727

YTD Electric Sales Volumes
GWh

	2019	2018
Residential	**4,305**	4,154
Commercial	**2,913**	2,907
Industrial	**1,001**	978
Other	**967**	1,126
Total	**9,186**	9,165

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $5 million to $156 million in Q2 2019, compared to $151 million in Q2 2018 due to higher production volumes as a result of customer growth and weather, partially offset by favourable generation mix related to increased lower-cost natural gas and solar usage. Year-to-date, regulated fuel for generation and purchased power decreased $21 million to $271 million in 2019, compared to $292 million in the same period in 2018, due to increased lower-cost natural gas and solar usage.

Q2 Production Volumes
GWh

	2019	2018
Natural gas	**4,665**	3,794
Coal	**364**	1,248
Oil and petcoke	**-**	10
Solar	**225**	14
Purchased power	**328**	199
Total	**5,582**	5,265

YTD Production Volumes
GWh

	2019	2018
Natural gas	**8,433**	7,239
Coal	**672**	1,883
Oil and petcoke	**-**	241
Solar	**377**	24
Purchased power	**423**	362
Total	**9,905**	9,749

Q2 Average Fuel Costs

US dollars	**2019**	2018
Dollars per Megawatt hour ("MWh")	**$ 28**	$ 29

YTD Average Fuel Costs

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

Average fuel cost per MWh decreased in Q2 2019 and year-to-date, compared to the same periods in 2018, primarily due to increased lower-cost natural gas usage and lower-cost solar usage.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Operating revenues – regulated electric	**$ 327**	$ 321	**$ 770**	$ 745
Regulated fuel for generation and purchased power (1)	**141**	137	**333**	312
Income from equity investments	**23**	25	**48**	50
Contribution to consolidated net income	**$ 42**	$ 48	**$ 138**	$ 138
Contribution to consolidated earnings per common share – basic	**$ 0.18**	$ 0.21	**$ 0.58**	$ 0.60
EBITDA	**$ 128**	$ 137	**$ 324**	$ 319

(1) Regulated fuel for generation and purchased power includes NSPI's fuel adjustment mechanism ("FAM") and fixed cost deferrals on the Condensed Consolidated Income Statement, 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
NSPI	**$ 19**	$ 23	**$ 90**	$ 88
Equity investment in NSPML	**12**	15	**26**	30
Equity investment in LIL	**11**	10	**22**	20
Contribution to consolidated net income	**$ 42**	$ 48	**$ 138**	$ 138

Net Income

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

For the millions of Canadian dollars	Three months ended June 30	Six months ended June 30
Contribution to consolidated net income – 2018	**$ 48**	**$ 138**
Increased operating revenues - see Operating Revenues – Regulated Electric below	6	25
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(4)	(21)
Increased FAM and fixed cost deferrals due to increased excess non-fuel revenues, partially offset by an increased current period under-recovery of fuel costs which includes the impact of the Maritime Link assessment	(10)	(6)
Increased OM&G expenses quarter-over-quarter primarily due to higher costs for vegetation management, power generation, variable compensation, and information technology	(6)	(2)
Increased depreciation and amortization due to increased property, plant and equipment	(3)	(6)
Decrease in income from equity investments	(2)	(2)
Decreased other expenses, net primarily due to lower non-current service pension costs in NSPI	7	11
Increased interest expense, net primarily due to increased long-term debt outstanding	(2)	(3)
Decreased income taxes quarter-over-quarter due to decreased non-deductible pension expense and decreased income before provision for income taxes. Year-over-year income taxes decreased due to decreased non-deductible pension expense	8	4
Contribution to consolidated net income – 2019	**$ 42**	**$ 138**

Canadian Electric Utilities' contribution to consolidated net income decreased in Q2 2019 due to a lower contribution from NSPI. This decrease was primarily due to the timing of regulatory deferrals and increased OM&G expenses. This was partially offset by decreased income taxes and other expenses, increased sales volume due to weather, and increased residential and commercial class sales volume growth. Canadian Electric Utilities' overall year-to-date contribution was consistent with the same period in 2018. The timing of regulatory deferrals causes quarterly earnings volatility, while full year results are more predictable.

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $6 million to $327 million in Q2 2019, compared to $321 million in Q2 2018. Year-to-date operating revenues increased $25 million to $770 million compared to $745 million for the same period in 2018. The increases in both periods were primarily as a result of increased sales volume due to weather, increased fuel related electricity pricing in 2019 and increased residential and commercial class sales volume growth. This was partially offset by the impact of the Maritime Link assessment.

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

Q2 Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**165**	$	157
Commercial		**94**		93
Industrial		**53**		54
Other		**8**		10
Total	**$**	**320**	$	314

YTD Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**417**	$	393
Commercial		**207**		203
Industrial		**108**		111
Other		**24**		24
Total	**$**	**756**	$	731

Q2 Electric Sales Volumes
GWh

	2019	2018
Residential	**1,023**	974
Commercial	**714**	710
Industrial	**591**	644
Other	**57**	69
Total	**2,385**	2,397

YTD Electric Sales Volumes
GWh

	2019	2018
Residential	**2,644**	2,492
Commercial	**1,598**	1,564
Industrial	**1,188**	1,268
Other	**200**	184
Total	**5,630**	5,508

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $4 million to $141 million in Q2 2019, compared to $137 million in Q2 2018. Year-to-date regulated fuel for generation and purchased power increased $21 million to $333 million compared to $312 million in the same period in 2018. Increases in both periods were primarily due to increased commodity prices partially offset by changes in generation mix. Year-to-date increases were also due to increased sales volumes.

Q2 Production Volumes
GWh

	2019	2018
Coal	**787**	856
Oil and petcoke	**313**	298
Natural gas	**352**	477
Purchased power – other	**229**	60
Total non-renewables	**1,681**	1,691
Wind and hydro	**410**	349
Purchased power – Independent Power Producers ("IPP")	**266**	295
Purchased power – Community Feed-in Tariff program ("COMFIT")	**130**	135
Biomass	**30**	42
Total renewables	**836**	821
Total production volumes	**2,517**	2,512

YTD Production Volumes
GWh

	2019	2018
Coal	**2,633**	2,502
Oil and petcoke	**628**	754
Natural gas	**596**	638
Purchased power – other	**370**	148
Total non-renewables	**4,227**	4,042
Wind and hydro	**781**	734
Purchased power – IPP	**636**	681
Purchased power – COMFIT	**293**	299
Biomass	**45**	82
Total renewables	**1,755**	1,796
Total production volumes	**5,982**	5,838

Q2 Average Fuel Costs

	2019	2018
Dollars per MWh	**56**	54

YTD Average Fuel Costs

	2019	2018
Dollars per MWh	**56**	53

Average fuel cost per MWh increased in Q2 2019 and year-to-date, compared to the same periods in 2018, primarily due to increased commodity pricing. In addition, year-to-date fuel costs have increased due to the timing of the payments of the Maritime Link assessment.

NSPI's FAM regulatory liability balance decreased $1 million from $161 million at December 31, 2018 to $160 million at June 30, 2019, primarily due to a refund to customers of the 2018 Maritime Link assessment and under-recovery of current period fuel costs. 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 and an increase in the application of excess non-fuel revenues.

ENL

Income from Equity Investments in NSPML and LIL

Income from equity investments for both Q2 2019 and year-to-date were consistent with the same periods in 2018. 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 regulatory approvals. 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 June 30 **2019**	 2018	Six months ended June 30 **2019**	 2018
Operating revenues – regulated electric	**$ 141**	$ 140	**$ 277**	$ 277
Regulated fuel for generation and purchased power (1)	**54**	53	**103**	107
Adjusted contribution to consolidated net income	**$ 17**	$ 14	**$ 29**	$ 26
Adjusted contribution to consolidated net income – CAD	**$ 23**	$ 18	**$ 39**	$ 33
After-tax equity securities mark-to-market gain (loss)	**1**	(1)	**2**	(2)
Contribution to consolidated net income	**$ 18**	$ 13	**$ 31**	$ 24
Contribution to consolidated net income – CAD	**$ 23**	$ 17	**$ 41**	$ 31
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$ 0.10**	$ 0.08	**$ 0.16**	$ 0.14
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.10**	$ 0.07	**$ 0.17**	$ 0.13
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.32**	$ 1.29	**$ 1.32**	$ 1.28
Adjusted EBITDA	**$ 50**	$ 49	**$ 97**	$ 93
Adjusted EBITDA – CAD	**$ 68**	$ 63	**$ 130**	$ 119

(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 June 30 **2019**	 2018	Six months ended June 30 **2019**	 2018
Emera Maine	**$ 9**	$ 5	**$ 17**	$ 13
ECI	**8**	9	**12**	13
Adjusted contribution to consolidated net income	**$ 17**	$ 14	**$ 29**	$ 26

Net Income

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

For the millions of US dollars	Three months ended June 30	Six months ended June 30
Contribution to consolidated net income – 2018	**$ 13**	**$ 24**
Operating revenues - see Operating Revenues - Regulated Electric below	1	-
Regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below	(1)	4
Decreased OM&G primarily due to higher capitalized overheads as a result of higher capital spending at Emera Maine	3	3
Other	2	-
Contribution to consolidated net income – 2019	**$ 18**	**$ 31**

Excluding the change in mark-to-market, Other Electric Utilities CAD contribution to consolidated net income increased $5 million in Q2 2019, compared to Q2 2018. Year-to-date, the CAD contribution increased $6 million compared to 2018. Emera Maine's contribution increased in both periods due to higher capitalized construction overheads in Q2 2019 and increased revenue due to favourable weather in Q2 2019, which was partially offset by unfavourable transmission revenue adjustments and lower transmission pool revenues. ECI's CAD contribution to consolidated net income in Q2 2019 and year-to-date was consistent with 2018.

The foreign exchange rate had minimal impact for the three and six months ended June 30, 2019.

Operating Revenues – Regulated Electric

Operating revenues increased $1 million to $141 million in Q2 2019, compared to $140 million in Q2 2018 due to increased sales volumes at GBPC due to weather and at Domlec reflecting the completion of hurricane restoration in 2018. These were partially offset by lower revenue at Emera Maine due to unfavourable transmission revenue adjustments, and lower transmission pool revenue as a result of lower rates. Year-to-date revenues were consistent when compared to the same period in 2018.

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

Q2 Electric Revenues
millions of USD

	2019	2018
Residential	**$ 49**	$ 48
Commercial	**69**	65
Industrial	**8**	8
Other (1)	**15**	19
Total	**$ 141**	$ 140

(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	**$ 100**	$ 95
Commercial	**129**	127
Industrial	**17**	17
Other (1)	**31**	38
Total	**$ 277**	$ 277

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

Q2 Electric Sales Volumes

GWh	**2019**	2018
Residential	**299**	287
Commercial	**366**	374
Industrial	**108**	103
Other	**7**	7
Total	**780**	771

YTD Electric Sales Volumes

GWh	**2019**	2018
Residential	**638**	615
Commercial	**735**	741
Industrial	**220**	205
Other	**14**	13
Total	**1,607**	1,574

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $1 million to $54 million in Q2 2019, compared to $53 million in Q2 2018, due to increased volumes at Domlec and higher purchased power expense at Emera Maine, partially offset by lower oil prices at BLPC and GBPC. Year-to-date, regulated fuel for generation and purchased power decreased $4 million to $103 million in Q2 2019, compared to $107 million in the same period in 2018, due to the expiration of a major purchased power contract at Emera Maine and lower oil prices at BLPC and GBPC, partially offset by increased volumes at Domlec.

Q2 Production Volumes
GWh

	2019	2018
Oil	**343**	331
Hydro	**6**	6
Solar	**4**	4
Purchased power	**8**	6
Total	**361**	347

YTD Production Volumes
GWh

	2019	2018
Oil	**662**	640
Hydro	**10**	10
Solar	**9**	8
Purchased power	**16**	12
Total	**697**	670

Q2 Average Fuel Costs

US dollars	**2019**	2018
Dollars per MWh	**123**	130

YTD Average Fuel Costs

US dollars	**2019**	2018
Dollars per MWh	**120**	127

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

Average fuel cost per MWh decreased in Q2 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Operating revenues – regulated gas (1)	**$ 179**	$ 171	**$ 448**	$ 440
Operating revenues – non-regulated	**3**	3	**6**	7
Total operating revenue	**$ 182**	$ 174	**$ 454**	$ 447
Regulated cost of natural gas	**45**	50	**148**	160
Income from equity investments	**5**	4	**10**	9
Contribution to consolidated net income	**$ 31**	$ 18	**$ 82**	$ 59
Contribution to consolidated net income – CAD	**$ 40**	$ 25	**$ 107**	$ 78
Contribution to consolidated earnings per common share – basic - CAD	**$ 0.17**	$ 0.11	**$ 0.45**	$ 0.34
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.34**	$ 1.29	**$ 1.33**	$ 1.26
EBITDA	**$ 74**	$ 59	**$ 176**	$ 153
EBITDA – CAD	**$ 98**	$ 77	**$ 233**	$ 196

(1) Operating revenues – regulated gas includes $10 million of finance income from Brunswick Pipeline (2018 - $10 million) for the three months ended June 30, 2019 and $21 million (2018 - $20 million) for the six months ended June 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
PGS	**$ 14**	$ 12	**$ 32**	$ 27
NMGC	**9**	(2)	**32**	15
Other	**8**	8	**18**	17
Contribution to consolidated net income	**$ 31**	$ 18	**$ 82**	$ 59

Net Income

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

For the millions of US dollars	Three months ended June 30	Six months ended June 30
Contribution to consolidated net income – 2018	**$ 18**	**$ 59**
Gas operating revenues - see Operating Revenues - Regulated Gas below	8	8
Decreased cost of natural gas sold - see Regulated Cost of Natural Gas below	5	12
Decreased depreciation and amortization due to accelerated amortization of assets related to manufactured gas plant environmental remediation costs in 2018 at PGS and reduced PGS depreciation rates in 2019 related to the settlement agreement to net amortization of manufactured gas plant environmental regulatory asset and 2018 tax reform benefits	1	6
Increased income tax expense due to increased income before provision for income taxes	(2)	(5)
Other	1	2
Contribution to consolidated net income – 2019	**$ 31**	**$ 82**

Gas Utilities and Infrastructure’s CAD contribution to consolidated net income increased $15 million compared to Q2 2018. Year-to-date, Gas Utilities and Infrastructure’s CAD contribution to consolidated net income increased $29 million compared to 2018. NMGC’s recognition of tax reform benefits from January 1, 2018 to June 30, 2019 resulted in a $12 million ($9 million USD) increase in net income for Q2 2019 and year-to-date, of which $8 million ($6 million USD) relates to 2018. Both periods also benefited from favourable weather in New Mexico. The year-to-date increase was also due to customer growth at PGS, lower depreciation and amortization in PGS and lower OM&G expense in PGS as the 2018 tax reform benefits were recorded through OM&G expense in 2018. These year-to-date increases were partially offset by lower revenues in PGS due to tax reform.

The impact of the change in the foreign exchange rate increased Q2 2019 and year-to-date 2019, CAD earnings by $1 million and $4 million, respectively.

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 $2 million USD decrease in revenue in Q2 2019 and a $5 million decrease year-to-date.

Gas Utilities and Infrastructure's operating revenues increased $8 million to $179 million in Q2 2019, compared to $171 million in Q2 2018. Year-to-date operating revenues increased $8 million to $448 million compared to $440 million in the same period in 2018. The increases in both periods were a result of the NMPRC's approval of NMGC retaining tax reform benefits from January 1, 2018 to June 30, 2019, favourable weather in New Mexico and customer growth at PGS. These increases were offset by lower base rates at PGS reflecting the impact of tax reform and less favourable weather. Year-to-date increases were also offset by lower clause-related revenues.

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

Q2 Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**70**	$	66
Commercial		**46**		49
Industrial (1)		**10**		9
Other (2)		**43**		37
Total (3)	**$**	**169**	$	161

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $10 million of finance income from Brunswick Pipeline (2018 – $10 million).

YTD Gas Revenues
millions of US dollars

		2019		**2018**
Residential	**$**	**212**	$	208
Commercial		**119**		123
Industrial (1)		**19**		18
Other (2)		**77**		71
Total (3)	**$**	**427**	$	420

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $21 million of finance income from Brunswick Pipeline (2018 – $20 million).

Q2 Gas Volumes
Therms (millions)

	2019	2018
Residential	**65**	58
Commercial	**177**	180
Industrial	**383**	315
Other	**75**	61
Total	**700**	614

YTD Gas Volumes
Therms (millions)

	2019	2018
Residential	**240**	214
Commercial	**440**	425
Industrial	**720**	632
Other	**136**	111
Total	**1,536**	1,382

Regulated Cost of Natural Gas

Regulated cost of natural gas decreased $5 million to $45 million in Q2 2019, compared to $50 million in Q2 2018. Year-to-date, regulated cost of natural gas decreased $12 million to $148 million in Q2 2019, compared to $160 million in the same period in 2018. The decrease was due to lower commodity costs in New Mexico in both periods, and due to lower commodity costs in Florida year-to-date.

Gas sales by type are summarized in the following table:

Q2 Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**141**	129
Transportation	**559**	485
Total	**700**	614

YTD Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**409**	376
Transportation	**1,127**	1,006
Total	**1,536**	1,382

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30 **2019**	2018	Six months ended June 30 **2019**	2018
Marketing and trading margin (1) (2)	**$ (28)**	$ (2)	**$ 26**	$ 67
Electricity and capacity sales (3) (4)	**-**	85	**116**	207
Other non-regulated operating revenue	**8**	12	**18**	22
Total operating revenues – non-regulated	**$ (20)**	$ 95	**$ 160**	$ 296
Intercompany revenue (5)	**4**	10	**13**	19
Non-regulated fuel for generation and purchased power (4)(6)	**2**	48	**66**	116
Income from equity investments	**9**	9	**17**	14
Interest expense, net	**82**	90	**175**	179
Adjusted contribution to consolidated net income (loss)	**$ (100)**	$ (75)	**$ (116)**	$ (91)
After-tax derivative mark-to-market gain (loss)	**$ (27)**	$ (20)	**$ 59**	$ 50
Contribution to consolidated net income (loss)	**$ (127)**	$ (95)	**$ (57)**	$ (41)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.42)**	$ (0.32)	**$ (0.49)**	$ (0.39)
Contribution to consolidated earnings per common share – basic	**$ (0.53)**	$ (0.41)	**$ (0.24)**	$ (0.18)
Adjusted EBITDA	**$ (41)**	$ 11	**$ 49**	$ 103

(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 $39 million in Q2 2019 (2018 - $27 million loss) and a gain of $83 million year-to-date (2018 – $37 million gain).

(3) Electricity and capacity sales exclude a pre-tax mark-to-market loss of nil in Q2 2019 (2018 - $6 million loss) and year-to-date gain of $2 million (2018 – $31 million gain).

(4) On March 29, 2019, Emera completed the sale of the NEGG facilities. Refer to the "Developments" section for further details.

(5) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.

(6) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $1 million in Q2 2019 (2018 - $3 million gain) and year-to-date $3 million loss (2018 – $3 million gain).

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

For the millions of Canadian dollars	Three months ended June 30 **2019**	2018	Six months ended June 30 **2019**	2018
Emera Energy	**$ (19)**	$ 2	**$ 33**	$ 57
Corporate	**(81)**	(78)	**(148)**	(149)
Other	**-**	1	**(1)**	1
Adjusted contribution to consolidated net income (loss)	**$ (100)**	$ (75)	**$ (116)**	$ (91)

Net Income

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

For the millions of Canadian dollars		Three months ended June 30		Six months ended June 30
Contribution to consolidated net income (loss) – 2018	**$**	**(95)**	**$**	**(41)**
Decreased marketing and trading margin - see Emera Energy below		(26)		(41)
Decreased electricity and capacity sales net of non-regulated fuel for generation and purchased power primarily due to the sale of Emera Energy's NEGG facilities in late Q1 2019		(39)		(41)
Decreased OM&G due to sale of NEGG facilities in late Q1 2019		16		15
Increased income tax recovery due to increased losses before provision for income taxes		11		13
Decreased depreciation due to sale of NEGG in late Q1 2019		11		20
Gain on sale of property in Florida, pre-tax		-		14
Decreased mark-to-market, net of tax, quarter-over-quarter primarily due to higher amortization of gas transportation assets, partially offset by change in existing positions on gas contracts. Year-over-year increased due to a larger reversal of mark-to-market losses in 2019, compared to 2018 and changes in existing positions on gas contracts in 2019, partially offset by higher amortization of gas transportation assets in 2019		(7)		9
Increased preferred stock dividends due to the issuance of preferred shares in Q2 2018		(4)		(8)
Other		6		3
Contribution to consolidated net income (loss) – 2019	**$**	**(127)**	**$**	**(57)**

Excluding the change in mark-to-market, Other's contribution to consolidated net income decreased by $25 million for the quarter and year-to-date compared to the same periods in 2018. In Q2 2019, the decrease was due to lower marketing and trading margin. Year-over-year, the decrease was primarily due to lower marketing and trading margin and higher preferred stock dividends, partially offset by the gain on sale of property in Florida and increased income tax recovery.

Emera Energy

Marketing and trading margin decreased $26 million to $(28) million in Q2 2019, compared to $(2) million in Q2 2018. Year-to-date margin decreased $41 million to $26 million in 2019, compared to $67 million for the same period in 2018. The decrease in both periods was due to less favourable market conditions in 2019 relative to 2018, particularly in Q2 2019 when unseasonably cool weather resulted in lower market prices and volatility. Fixed cost commitments for gas transportation and storage assets were also higher in Q2 2019, compared to Q2 2018.

The foreign exchange rate had minimal impact for the three and six months ended June 30, 2019.

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 sufficient 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 expects to invest approximately $6.5 billion over the three-year period from 2019 to 2021 on rate base growth in the Company's regulated utilities. Over 85 per cent of the investment is expected to be in Florida and Nova Scotia. 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, NEGG and other select asset sales, to support normal operations, repayment of existing debt and capital requirements. 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 six months ended June 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		**775**		767		8
Change in working capital		**32**		97		(65)
Operating activities		**807**		864		(57)
Investing activities		**(264)**		(984)		720
Financing activities		**(515)**		1		(516)
Effect of exchange rate changes on cash, cash equivalents, restricted cash and cash included in assets held for sale		**(16)**		15		(31)
Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period	**$**	**384**	$	399	$	(15)

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $57 million to $807 million for the six months ended June 30, 2019, compared to $864 million for the same period in 2018.

Cash from operations before changes in working capital was overall comparable quarter-over-quarter.

Changes in working capital decreased operating cash flows by $65 million. The decrease was due to unfavourable changes in cash collateral at NSPI and Emera Energy, and unfavourable changes in accounts payable at NSPI, Tampa Electric and NMGC. These were partially offset by a refund of $146 million ($109 million USD) of alternative minimum tax credit carryforwards in April 2019.

Cash Flow used in Investing Activities

Net cash used in investing activities decreased $720 million to $264 million for the six months ended June 30, 2019, compared to $984 million for the same period in 2018. In 2019, Emera received proceeds of $860 million on disposition of the NEGG and Bayside facilities, and on sale of property in Florida. These proceeds were partially offset by an increase in capital expenditures.

Capital expenditures for the six months ended June 30, 2019, including AFUDC, were $1,130 million compared to $964 million for the same period in 2018. Details of the 2019 capital spend by segment are shown below:

- $647 million - Florida Electric Utility (2018 – $565 million);
- $159 million - Canadian Electric Utilities (2018 – $159 million);
- $83 million - Other Electric Utilities (2018 – $74 million);
- $185 million - Gas Utilities and Infrastructure (2018 – $140 million); and
- $56 million - Other (2018 – $26 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $516 million to $515 million for the six months ended June 30, 2019, compared to net cash provided by financing activities of $1 million for the same period in 2018. The increase was due to repayment of corporate long-term debt, repayments at NSPI and the 2018 repayment of debt at TECO Finance. These were partially offset by proceeds from long-term debt at NSPI in 2019 and a preferred share issuance in 2018.

Contractual Obligations

As at June 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)	$ 418	$ 542	$ 1,666	$ 524	$ 1,048	$ 10,292	$ 14,490
Interest payment obligations (2)(3)	341	643	596	560	533	7,047	9,720
Purchased power (4)(5)	129	211	220	223	226	2,139	3,148
Transportation (6)	282	394	309	259	225	2,188	3,657
Pension and post-retirement obligations (7)(8)	18	33	34	35	35	1,026	1,181
Capital projects (9)	409	205	46	12	4	17	693
Fuel, gas supply and storage	281	168	52	8	4	-	513
Asset retirement obligations	2	11	43	1	1	362	420
Long-term service agreements (10)(11)	21	43	30	25	20	112	251
Equity investment commitments (12)	-	-	190	-	-	-	190
Leases and other (13)	7	7	9	9	7	90	129
Demand side management	21	1	-	-	-	-	22
Long-term payable	2	5	5	5	5	-	22
Convertible debentures	-	-	-	-	-	2	2
	$ 1,931	$ 2,263	$ 3,200	$ 1,661	$ 2,108	$ 23,275	$ 34,438

As noted below, Contractual Obligations at June 30, 2019 include contractual commitments related to Emera Maine. On completion of the sale of Emera Maine, 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 $484 million related to Emera Maine ($39 million in 2020; $118 million in 2022; $52 million in 2023 and $275 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 June 30, 2019, including any expected required payment under associated swap agreements.

(3) Includes $346 million related to Emera Maine ($9 million in 2019; $20 million in 2020; $18 million in 2021; $13 million in 2022; $12 million in 2023 and $274 million thereafter).

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

(5) Includes $182 million related to Emera Maine ($6 million in 2019; $13 million in 2020; $13 million in 2021; $13 million in 2022; $13 million in 2023 and $124 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 $89 million related to Emera Maine ($3 million in 2019; $7 million in 2020; $7 million in 2021; $7 million in 2022; $7 million in 2023 and $58 million thereafter).

(9) Includes $320 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 $30 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($8 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, and transmission rights.

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, 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	$ 390	$ 510
TECO Finance, Inc. – in USD – Operating credit facilities	March 2020 - March 2022	900	545	355
NSPI – Operating credit facility	October 2023	600	177	423
TEC - in USD - credit facilities (1)	March 2021 - March 2022	475	387	88
NMGC – in USD – Operating credit facility	March 2022	125	56	69
Emera Maine – in USD – Operating credit facility	February 2023	80	42	38
Other - in USD - Operating credit facility	Various	32	17	15

(1) This facility is available for use by Tampa Electric and PGS. At June 30, 2019, Tampa Electric had utilized $343 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 June 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 $38 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 December 2019. This letter of credit is renewed annually. The amount committed as of June 30, 2019 was $6 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 June 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 $27 million for the three months ended June 30, 2019 (2018 - $27 million) and $54 million for the six months ended June 30, 2019 (2018 - $51 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 June 30, 2019 (2018 - $6 million) and $34 million for the six months ended June 30, 2019 (2018 - $16 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at June 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. These employees are governed by a Collective Agreement that expired on March 31, 2019. NSPI is in the process of renegotiating the current terms of this Collective Agreement. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

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	**June 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Operating revenues – regulated	**$ -**	$ 2	**$ (2)**	$ 4
Non-regulated fuel for generation and purchased power	**-**	(1)	**-**	3
Effective net gains (losses)	**$ -**	$ 1	**$ (2)**	$ 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	**June 30 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 48**	$ 104
Regulatory assets (current and other assets)	**53**	6
Derivative instrument liabilities (current and long-term liabilities)	**(52)**	(6)
Regulatory liabilities (current and long-term liabilities)	**(55)**	(115)
Net asset (liability)	**$ (6)**	$ (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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Regulated fuel for generation and purchased power (1)	**$ 3**	$ 1	**$ 7**	$ 5
Net gains (losses)	**$ 3**	$ 1	**$ 7**	$ 5

(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	**June 30 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 44**	$ 62
Derivative instrument liabilities (current and long-term liabilities)	**(202)**	(354)
Net derivative instrument assets (liabilities)	**$ (158)**	$ (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 June 30				Six months ended June 30		
		2019		2018		**2019**		2018
Operating revenue - non-regulated	**$**	**45**	$	21	**$**	**249**	$	149
Non-regulated fuel for purchased power		**(3)**		2		**(5)**		-
Net gains (losses)	**$**	**42**	$	23	**$**	**244**	$	149

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		**June 30 2019**		December 31 2018
Derivative instrument assets (current and other assets)	**$**	**23**	$	1
Net derivative instrument assets (liabilities)	**$**	**23**	$	1

Other Derivatives Recognized in Net Income

For the three months ended June 30, 2019, the Company had unrealized gains on equity derivatives of $9 million (2018 – nil) and $23 million for the six months ended June 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 June 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 June 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 six months ended June 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.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q2 2019**	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017
Operating revenues	**$ 1,378**	$ 1,818	$ 1,799	$ 1,495	$ 1,423	$ 1,807	$ 1,473	$ 1,427
Net income (loss) attributable to common shareholders	**103**	312	231	118	90	271	(228)	81
Adjusted net income attributable to common shareholders	**130**	224	167	191	111	202	137	118
Earnings per common share – basic	**0.43**	1.32	0.98	0.51	0.38	1.17	(1.06)	0.38
Earnings per common share – diluted	**0.43**	1.32	0.98	0.50	0.38	1.17	(1.06)	0.38
Adjusted earnings per common share – basic	**0.54**	0.95	0.71	0.82	0.48	0.87	0.64	0.55

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.