Management's Discussion & Analysis

As at November 8, 2018

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments ("Emera") during the third quarter and year-to-date of 2018 relative to the same periods in 2017; and its financial position as at September 30, 2018 relative to December 31, 2017. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments. The Company's activities are carried out through six business segments: Emera Florida and New Mexico, Nova Scotia Power Inc., Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other.

This discussion and analysis should be read in conjunction with the Emera Incorporated unaudited condensed consolidated interim financial statements and supporting notes as at and for the nine months ended September 30, 2018; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2017. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

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")
Peoples Gas System ("PGS") – Gas Division of TEC	FPSC
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
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")
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	National Energy Board ("NEB")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline LLC ("M&NP")	NEB and FERC
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")

All amounts are in Canadian dollars ("CAD"), except for the Emera Florida and New Mexico, Emera Maine and Emera Caribbean 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", "could", "estimates", "expects", "intends", "may", "plans", "projects", "schedule", "should", "budget", "forecast", "might", "will", "would", "targets" 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; capital market and liquidity risk; future dividend growth; timing and costs associated with certain capital projects; 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; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; 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

Emera is a geographically diverse energy and services company. The Company has investments in electricity generation, transmission and distribution and gas transmission and distribution, predominantly within rate-regulated utilities which support strong, consistent earnings and cash flow. Emera seeks to provide its customers with reliable, cost-effective and sustainable energy products and services, and provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States and the Caribbean.

For investors, Emera seeks to deliver consistent earnings, cash flow and long-term growth, and accordingly, the primary measures of performance are annual dividend growth, earnings per common share growth, adjusted earnings per common share growth (a non-GAAP measure described in the Non-GAAP Financial Measures section below) and total shareholder return. The Company has significant near term regulated rate base investment opportunities, including Tampa Electric's $1.7 billion USD investment in 600 MW of new solar generation and the modernization of the Big Bend Power Station. With the Company's significant investment profile, and giving consideration to developments in the capital markets and other factors, in August 2018, Emera considered it prudent to reduce its annual dividend growth target from eight per cent through 2020 to a range of four to five per cent through 2021. The Company continues to target a long-term dividend payout ratio of 70 to 75 per cent. The Company expects that its dividend payout ratio will be higher than this long-term target over this guidance period. Emera continues to target achieving a minimum of 75 per cent of its adjusted net income from its rate regulated utilities.

Energy markets worldwide, in particular across North America, are undergoing foundational changes that have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, lower-cost natural gas, growing demand for new electric heating and cooling solutions, the requirement for large-scale transmission projects to deliver new energy sources to customers, technological developments, and environmental concerns. These environmental concerns include a desire to reduce emissions of carbon dioxide and other greenhouse gases and the potential system impacts of climate change, including changes in global and regional weather patterns, changes in the frequency and intensity of extreme weather events, and rising sea levels. At the core of Emera's electric utilities strategy is identifying opportunities to invest in the transition from higher-carbon methods of electricity generation to lower-carbon alternatives, and the related transmission and distribution infrastructure to deliver that energy to market. Emera's strategy for its gas utilities is to invest in infrastructure renewal and expansion within existing service territories.

The energy sector continues to be impacted by mandated and incented carbon reductions throughout North America and in the Caribbean. It is unclear whether economic volatility, government policy and lower fossil fuel prices will slow the pace of this change in the industry. Investment in wind, solar, and hydro generation, natural gas and new transmission infrastructure is likely to continue across the sector despite potential cost differential with more carbon-intensive generating options. The capital spending requirements related to these investments will need to be managed within the context of overall energy pricing.

In Florida, the Company is investing in a number of initiatives, including solar generation, modernization of coal-fired generation and natural gas infrastructure that will reduce carbon emissions. In Nova Scotia, the Company has invested in wind energy, biomass and hydroelectricity and is on track to meet a minimum 40 per cent renewable standard by 2020. In the Caribbean, Emera is similarly focused on introducing cleaner generation alternatives, with an emphasis on affordability and fuel cost stability for its customers.

Emera is investing in electricity transmission to deliver new renewable energy to market. Emera's interest in the Maritime Link and Labrador Island Link investments will contribute to the transformation of the electricity market in the Atlantic provinces, enabling growth in the availability of clean, renewable energy for the region. In addition, the Atlantic provinces will benefit from enhanced connection to the northeastern United States, providing potential for excess renewable energy to be delivered throughout that region.

Emera Energy is a physical energy marketing and trading business, complemented by a portfolio of competitive electricity generation facilities. A substantial portion of Emera Energy's activities are in northeastern North America, and its market knowledge, focus on customer service and robust risk management are key success factors. Unlike the vast majority of Emera's businesses, Emera Energy is not rate-regulated.

Emera's ability to achieve its strategy depends on its ability to apply a collaborative approach to strategic partnerships, ability to find creative solutions within and across multiple jurisdictions and its experience dealing with complex projects and investment structures. The Company will continue to make investments in its regulated utilities to benefit customers and focus on providing rate stability. From time to time, Emera will make acquisitions, both regulated and unregulated, where the business or asset acquired aligns with Emera's strategic initiatives and delivers shareholder value.

To ensure stability in the utilities' net income and cash flows, Emera employs operating and governance models that focus on safety and operational excellence, a customer focus through service reliability and rate stability, proactive stakeholder engagement, constructive regulatory approaches and employee engagement and development.

In delivering on its strategic objectives, Emera has grown and expects to continue to grow its asset base. Over the last 10 years, Emera's ability to generate cash and to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. Emera's primary sources of funding for its current capital investment profile is expected to consist of internally generated cash flows, debt raised at the operating company level in support of the growth profile of each business and select asset sales. Equity capital markets, including preferred shares and the dividend reinvestment plan, will continue to support the company's future growth. Maintaining investment grade credit ratings is an important component of Emera's strategy.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments and foreign currency exchange can have a material impact on the financial results for a specific period. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

The effect of foreign currency exchange on Emera's net income is noteworthy, as it is expected that approximately 70 per cent of Emera's adjusted net income will be derived from subsidiaries with a US functional currency. Emera's consolidated net income and cash flows will be impacted by movements in the US dollar relative to the Canadian dollar. In general, Emera benefits from a weakening Canadian dollar and is adversely impacted by a strengthening Canadian dollar. Emera generally hedges transactional exposure but does not hedge translational exposure.

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

For the third quarter and year-to-date in 2018 and 2017, Emera calculated 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 Emera Caribbean and Corporate and Other.

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 the ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these adjustments for evaluation of performance and incentive compensation.

Refer to the “Consolidated Financial Review”, “Emera Energy”, “Emera Caribbean” and “Corporate and Other” sections for further details on mark-to-market adjustments.

In Q4 2017, due to the enactment of the US Tax Cuts and Jobs Act of 2017, the Company recorded a non-cash income tax expense resulting from the provisional revaluation of the existing US non-regulated net deferred income tax assets. The effect of this provisional revaluation was excluded from the calculation of 2017 adjusted net income. The Company continues to monitor certain aspects of the Act, including the valuation of refundable alternative minimum tax credits, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (“SAB 118”). No measurement period adjustments have been recognized year-to-date in 2018.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Net income attributable to common shareholders	**$ 118**	$ 81	**$ 479**	$ 494
After-tax mark-to-market gain (loss)	**$ (73)**	$ (37)	**$ (25)**	$ 107
Adjusted net income attributable to common shareholders	**$ 191**	$ 118	**$ 504**	$ 387
Earnings per common share – basic	**$ 0.51**	$ 0.38	**$ 2.06**	$ 2.32
Adjusted earnings per common share – basic	**$ 0.82**	$ 0.55	**$ 2.17**	$ 1.82

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 September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Net income (1)	**$ 141**	$ 99	**$ 516**	$ 531
Interest expense, net	**176**	170	**527**	523
Income tax expense (recovery)	**(33)**	45	**29**	191
Depreciation and amortization	**236**	207	**687**	644
EBITDA	**520**	521	**1,759**	1,889
Mark-to-market gain (loss), excluding income tax and interest	**(105)**	(54)	**(36)**	153
Adjusted EBITDA	**$ 625**	$ 575	**$ 1,795**	$ 1,736

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

2018

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

After-tax mark-to-market losses increased $36 million to $73 million in Q3 2018 compared to $37 million in Q3 2017, mainly due to changes in Emera Energy's existing positions on gas contracts, partially offset by lower amortization of gas transportation assets in Q3 2018. Year-to-date, after-tax mark-to-market gains decreased $132 million to a $25 million loss in 2018 compared to a $107 million gain for the same period in 2017. This decrease, primarily related to Emera Energy, was due to changes in existing positions on long-term natural gas contracts in the first quarter of 2017 and a larger reversal of mark-to-market losses in the first quarter of 2017 compared to 2018, partially offset by lower amortization of gas transportation assets in 2018.

Florida State Tax Apportionment

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

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
Adjusted net income (loss)	**2018**	2017	**2018**	2017
Emera Florida and New Mexico	**$ 140**	$ 120	**$ 327**	$ 302
NSPI	**15**	7	**103**	106
Emera Maine	**17**	13	**33**	38
Emera Caribbean	**14**	12	**31**	30
Emera Energy	**19**	(1)	**76**	(2)
Corporate and Other	**(14)**	(33)	**(66)**	(87)
Adjusted net income attributable to common shareholders	**$ 191**	$ 118	**$ 504**	$ 387
After-tax mark-to-market gain (loss)	**(73)**	(37)	**(25)**	107
Net income attributable to common shareholders	**$ 118**	$ 81	**$ 479**	$ 494

The following table highlights significant changes in adjusted net income from 2017 to 2018.

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2017	**$ 118**	**$ 387**
Florida state tax apportionment	23	23
Emera Energy	20	78
Emera Florida and New Mexico	20	25
NSPI	8	(3)
Emera Maine	4	(5)
NSPML and LIL equity earnings	2	18
Other	(4)	(19)
Adjusted net income – 2018	**$ 191**	**$ 504**

Refer to the segment financial highlights for further details of business unit contributions.

For the millions of Canadian dollars	Nine months ended September 30	
	2018	2017
Operating cash flow before changes in working capital	**$ 1,237**	$ 956
Change in working capital	**156**	85
Operating cash flow	**$ 1,393**	$ 1,041
Investing cash flow	**$ (1,565)**	$ (1,273)
Financing cash flow	**$ 121**	$ 62

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Total assets	**$ 30,309**	$ 28,771
Total long-term debt (including current portion)	**$ 14,499**	$ 13,881

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

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Variance	Nine months ended September 30		Variance
	2018	2017		**2018**	2017	
Operating revenues	**$ 1,495**	$ 1,427	$ 68	**$ 4,725**	$ 4,753	$ (28)
Operating expenses	**1,257**	1,137	(120)	**3,758**	3,577	(181)
Income from operations	**238**	290	(52)	**967**	1,176	(209)
Income from equity investments	**41**	34	7	**121**	90	31
Other income (expenses)	**5**	(10)	15	**(16)**	(21)	5
Interest expense, net	**176**	170	(6)	**527**	523	(4)
Income tax expense (recovery)	**(33)**	45	78	**29**	191	162
Net income	**141**	99	42	**516**	531	(15)
Net income attributable to common shareholders	**118**	81	37	**479**	494	(15)
After-tax mark-to-market gain (loss)	**(73)**	(37)	(36)	**(25)**	107	(132)
Adjusted net income attributable to common shareholders	**$ 191**	$ 118	$ 73	**$ 504**	$ 387	$ 117
Earnings per common share – basic	**$ 0.51**	$ 0.38	$ 0.13	**$ 2.06**	$ 2.32	$ (0.26)
Earnings per common share – diluted	**$ 0.50**	$ 0.38	$ 0.12	**$ 2.05**	$ 2.31	$ (0.26)
Adjusted earnings per common share – basic	**$ 0.82**	$ 0.55	$ 0.27	**$ 2.17**	$ 1.82	$ 0.35
Dividends per common share declared	**$ 1.1525**	$ 1.0875	$ 0.0650	**$ 2.2825**	$ 2.1325	$ 0.1500
Adjusted EBITDA	**$ 625**	$ 575	$ 50	**$ 1,795**	$ 1,736	$ 59

Operating revenues

For the third quarter of 2018, operating revenues increased $68 million compared to the third quarter of 2017. Absent increased mark-to-market losses of $55 million, operating revenues increased $123 million due to:

- $38 million increase at Emera Florida and New Mexico primarily as a result of a stronger USD;
- $35 million increase at New England Gas Generation (“NEGG”) reflecting more favourable market conditions and higher capacity prices in Q3 2018;
- $27 million increase at NSPI as a result of increased sales volumes due to load growth and weather; and
- $10 million increase at Emera Energy Services (“EES”) driven primarily by the impact of warm weather in Q3 2018.

Year-to-date in 2018, operating revenues decreased $28 million compared to the same period in 2017. Absent decreased mark-to-market gains of $196 million, operating revenues increased $168 million due to:

- $110 million increase at NEGG reflecting higher capacity prices in 2018, more favourable market conditions in 2018 and an unplanned outage at the Bridgeport facility in 2017;
- $72 million increase in NSPI revenues as a result of the 2017 refund to customers of prior year’s over-recovery of fuel costs, increased sales volumes due to load growth, and increased fuel-related electricity pricing, partially offset by the impact of the Maritime Link assessment; and
- $53 million increase in marketing and trading margin at EES driven primarily by the impact of cold weather in Q1 2018 and warm weather in Q3 2018.

These year-to-date favourable impacts were partially offset by decreases of:

- $29 million at Emera Florida and New Mexico due to the impact of a stronger CAD, lower electric revenues due to the timing of clause recoveries at Tampa Electric and lower commodity costs in New Mexico. These decreases were partially offset by higher electric sales volumes due to weather and higher base rates related to the Polk Power Station expansion and solar projects at Tampa Electric, as well as increased gas revenues due to favourable customer growth and weather in PGS; and
- $27 million at Bayside Power due to decreased electricity sales reflecting renegotiation of the Bayside Power power purchase agreement ("PPA") for the winter of 2017/2018.

Operating expenses

For the third quarter of 2018, operating expenses increased $120 million compared to the third quarter of 2017. Absent increased mark-to-market gains of $2 million, operating expenses increased $122 million due to:

- $75 million increase at Emera Florida and New Mexico as a result of a weaker CAD and increased operating, maintenance and general ("OM&G") at Tampa Electric from the regulatory agreement to net storm costs and the 2018 tax reform benefits; and
- $22 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and higher commodity prices, partially offset by decreased fuel adjustment mechanism ("FAM") and fixed cost deferrals.

Year-to-date in 2018, operating expenses increased $181 million compared to the same period in 2017. Absent increased mark-to-market gains of $9 million, operating expenses increased $190 million due to:

- $85 million increase at Emera Florida and New Mexico as a result of increased OM&G at Tampa Electric from the regulatory agreement to net storm costs and the 2018 tax reform benefits;
- $74 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and increased commodity pricing, partially offset by decreased FAM and fixed cost deferrals;
- $51 million increase at NEGG due to an increase in generation volumes in 2018 reflecting the impact of the unplanned outage at Bridgeport Energy in 2017 and more favourable market conditions in Q3 2018; and
- $43 million increase in depreciation and amortization due to normal asset growth across the business.

These unfavourable impacts were partly offset by a $27 million decrease at Bayside Power due to decreased natural gas purchases reflecting renegotiation of the Bayside Power PPA for the winter of 2017/2018.

Income from equity investments

The increase in income from equity investments for the third quarter in 2018 compared to the third quarter in 2017 was due to increased capacity prices at Bear Swamp. Year-to-date in 2018 compared to the same period in 2017, the increase was also due to higher earnings from NSPML.

Income tax expense (recovery)

The decrease in income tax expense for the third quarter and year-to-date compared to the same periods in 2017 was due to the reduction of the US federal corporate income tax rate, decreased income before provision for income taxes, remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors and amortization of deferred tax regulatory liabilities in the US utilities.

As a result of the US Tax Cuts and Jobs Act of 2017 the US federal corporate income tax rate was reduced from 35 per cent to 21 per cent. This reduction resulted in a significant decrease in income tax expense, however the impact to earnings was minimal. This was a result of the favourable impact of the reduced tax rate on Emera Energy earnings which was offset by the unfavourable impact of reduced tax recovery on losses arising from Corporate borrowing costs. The impact on US based regulated utilities earnings was immaterial. The tax benefits from the reduced rates in Tampa Electric were netted against deferred storm costs for 2018. Tax benefits deferred by PGS are being netted against the amortization of its manufactured gas plant ("MGP") environmental regulatory asset in 2018. Tampa Electric and PGS tax benefits will be adjusted in rates starting in 2019. New Mexico tax benefits are being addressed through the ongoing rate case proceedings. Certain of the tax benefits for Emera Maine are reflected in rates effective July 1, 2018 with other components being deferred to be addressed in future regulatory proceedings.

Net income and adjusted net income attributable to common shareholders

For the third quarter in 2018, net income attributable to common shareholders was unfavourably impacted by the $36 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 $73 million. The increase was due to the tax benefit recorded as a result of remeasurement of certain deferred tax balances due to the change in Florida state tax apportionment factors and higher contributions from Emera Energy and Emera Florida and New Mexico.

Year-to-date in 2018, net income attributable to common shareholders was unfavourably impacted by the $132 million decrease in after-tax mark-to-market gains primarily related to Emera Energy. Absent the unfavourable mark-to-market changes, adjusted net income attributable to common shareholders increased $117 million. The increase was due to higher contributions from Emera Energy, Emera Florida and New Mexico and NSPML and the tax benefit recorded as a result of the remeasurement of certain deferred tax balances due to the change in Florida state tax apportionment factors.

Earnings and adjusted earnings per common share – basic

Earnings per common share – basic were higher for the third quarter due to higher earnings, partially offset by the impact of the increase in the weighted average number of common shares outstanding reflecting the issuance of shares in December 2017. Year-to-date, earnings per common share – basic were lower due to decreased earnings and the impact of the increase in the weighted average number of common shares outstanding.

Adjusted earnings per common share – basic were higher for the third quarter and year-to-date due to higher adjusted earnings, partially offset by the increase in the weighted average of common shares outstanding.

Effect of Foreign Currency Translation

Emera operates globally, 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 operations from 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 2018 and 2017 are as follows:

	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2018	2017	**2018**	2017	2017
Weighted average CAD/USD exchange	**$ 1.31**	$ 1.26	**$ 1.29**	$ 1.30	$ 1.30
Period end CAD/USD exchange rate	**$ 1.29**	$ 1.25	**$ 1.29**	$ 1.25	$ 1.25

The weakening of the Canadian dollar increased earnings by $5 million and adjusted earnings by $8 million in Q3 2018 compared to Q3 2017. The strengthening of the CAD decreased earnings by $8 million and adjusted earnings by $3 million year-to-date in 2018 compared to the same period in 2017.

Consistent with the Company's risk management policies, Emera partially manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

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

millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Emera Florida and New Mexico	**$ 108**	$ 95	**$ 254**	$ 232
Emera Maine	**12**	10	**25**	29
Emera Caribbean	**11**	9	**24**	23
Emera Energy (1)	**20**	1	**65**	2
	151	115	**368**	286
Corporate and Other (2)	**(32)**	(29)	**(97)**	(87)
Total (3)	**$ 119**	$ 86	**$ 271**	$ 199

(1) Includes Emera Energy's US dollar adjusted net income from EES, NEGG and Bear Swamp.
(2) Corporate and Other includes interest expense on US dollar denominated debt, net of interest income on an intercompany US dollar loan to Emera Energy.
(3) Amounts above do not include the impact of mark-to-market.

BUSINESS OVERVIEW AND OUTLOOK

Emera continues to monitor certain aspects of the US Tax Cuts and Jobs Act of 2017 including interest deductibility and the valuation of refundable alternative minimum tax credits. The Company believes the majority of its US based financing interest can be properly allocable, in accordance with the Act, to its US regulated utilities and is therefore exempt from interest deductibility limitations.

Emera Florida and New Mexico

Emera Florida and New Mexico includes TECO Energy, the parent company of TEC, NMGC, SeaCoast and TECO Finance. TEC consists of two divisions; Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida; and PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas, serving customers in Florida. NMGC is a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a natural gas transmission company offering services in Florida.

Emera Florida and New Mexico's earnings are most directly impacted by the rate of return on equity and the capital structures approved by the FPSC and NMPRC, the prudent management of operating costs, the approved recovery of regulatory deferrals, weather and its impact on energy sales, and the timing and amount of capital expenditures.

The Florida utilities anticipate earning within their allowed ROE ranges in 2018 and expect rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2018 to be in line with 2017, reflecting economic growth in Florida. PGS expects customer growth rates in 2018 to be higher than 2017, reflecting economic growth and the optimization of existing opportunities as the utility increases its market penetration in Florida. Assuming normal weather in the fourth quarter of 2018, sales volumes are expected to increase consistent with customer growth.

On May 24, 2018, Tampa Electric announced its intention to invest approximately $850 million USD during 2018 through 2023 to modernize the Big Bend Power Station. Refer to the "Developments" section for further details.

In September 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new utility-scale solar photovoltaic projects across its service territory. On November 6, 2017, the FPSC approved a settlement agreement allowing a base rate adjustment that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects that will be phased in from late 2018 through early 2021. On May 8, 2018, the FPSC approved Tampa Electric's first solar base rate adjustment ("SoBRA"). This SoBRA represents 145 MW and $24 million USD annually in estimated revenue requirements. Tampa Electric began collecting these revenues in September 2018 as the related assets were placed in service. On October 29, 2018, the FPSC approved Tampa Electric's second SoBRA. This SoBRA, effective January 1, 2019, represents 260 MW and $46 million USD annually in estimated revenue requirements.

In September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs of approximately $102 million USD. The amount charged to the storm reserve exceeded the balance in the reserve by $47 million USD. Tampa Electric petitioned the FPSC on December 28, 2017 for recovery of estimated restoration costs in excess of the storm reserve for several named storms and to replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013. An amended petition was filed with the FPSC on January 30, 2018.

On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric authorizing the utility to net the estimated amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. In Q1 2018, Tampa Electric recorded OM&G expense and a regulatory liability of $19 million USD to offset tax reform benefits. Beginning April 1, 2018, this deferral of first quarter tax reform benefits is being amortized over the balance of the year as a credit against the recognition of storm expense. In total, OM&G expense due to the allowed netting of the storm cost recovery with tax reform benefits, net of amortization of first quarter tax reform benefits, was approximately $32 million USD for Q3 2018 and $80 million USD year-to-date.

Tampa Electric's final storm costs, subject to netting and final impact of tax reform on base rates, will be determined in separate regulatory proceedings. Any difference will be trued up and returned to customers in 2020. On August 20, 2018, the FPSC approved a reduction in base rates of $103 million USD annually beginning in 2019 as a result of lower tax expense.

On September 12, 2018, the FPSC approved a settlement agreement filed by PGS authorizing the utility to amortize $11 million USD of its MGP environmental regulatory asset and net it against its estimated 2018 tax reform benefits. Beginning in January 2019, PGS will lower base rates by $12 million USD to reflect the impact of tax reform.

NMGC expects earnings to be higher than the prior year due to the effects of colder weather throughout the first quarter of 2018 and lower tax expense as a result of tax reform. Customer growth rates are expected to be consistent with 2017, reflecting expectations for housing starts and new connections. NMGC filed a rate case, including the impact of tax reform, on February 26, 2018. A hearing in the rate case was held on September 24, 2018, where a stipulation agreement was presented. A second hearing in the rate case related to 2018 tax reform benefits is scheduled for December 2018. A decision by the NMPRC on the rate case and on 2018 tax reform benefits is expected in early 2019.

In 2018, Emera Florida and New Mexico expects to invest approximately $1.3 billion USD (2017 - $700 million USD), including allowance for funds used during construction ("AFUDC"), in capital projects. Capital projects support normal system reliability and growth at the three utilities, including capital projects at Tampa Electric for transmission and distribution storm hardening. The increase in investment over 2017 is primarily due to the investment in the solar photovoltaic projects and the modernization of the Big Bend Power Station at Tampa Electric.

PGS will make investments to expand its system and support customer growth, including investments in the construction of compressed natural gas fueling stations and continued replacement of obsolete plastic, cast iron and bare steel pipe.

On April 4, 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. ("Seminole") to provide long-term firm gas transportation service to Seminole's new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast will construct and operate a twenty-one mile 30-inch pipeline lateral that is anticipated to go into service in 2022. The estimated capital investment for this project is projected to be in the range of $100 million to $120 million USD with the majority of the investment expected in 2020 and 2021.

NMGC will continue to invest in system improvements by replacing legacy pipe and making pipeline integrity management improvements.

NSPI

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, providing electricity generation, transmission and distribution services to customers.

NSPI's earnings are most directly impacted by the range of ROE and capital structure approved by the UARB, the prudent management and approved recovery of operating costs, electric sales volumes, weather, the approved recovery of regulatory deferrals and the timing and amount of capital expenditures.

NSPI anticipates earning within its allowed ROE range in 2018 and expects modest rate base growth which will deliver a similar modest increase in earnings.

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

The Government of Canada ("Government") introduced the Pan-Canadian Framework on Clean Growth and Climate Change in early 2017. As part of the framework, in February 2018, the Government introduced proposed changes to the greenhouse gas coal regulations designed to remove coal fired generation by 2030, subject to equivalency agreements. At that time, a regulation was introduced specifying the emission intensities required for new natural gas fired generation and for boiler conversions from coal to natural gas. In June 2018, the Government announced carbon pricing backstop legislation, which will apply in jurisdictions without carbon pricing systems or "top-up" systems that do not meet established benchmarks. In September 2018, the Government of Nova Scotia submitted its plan for carbon pricing for the province, which consisted of a cap and trade program, to the Government of Canada. On October 23, 2018, the Government of Canada confirmed that the program was acceptable as a price on carbon. This program will commence on January 1, 2019 and will include a grant to NSPI of 22 million metric tons of carbon dioxide allowances for the four year compliance period of 2019 through 2022. NSPI is in the process of assessing any impacts of compliance with the cap and trade program. The Government is continuing to develop a clean fuel standard with the expectation that it will not apply to the electricity sector until 2022 at the earliest. NSPI anticipates that any costs prudently incurred to comply with regulations associated with the Pan-Canadian Framework on Clean Growth and Climate Change will be recoverable under NSPI's regulatory framework.

In June 2018, the UARB approved NSPI's $133 million capital application to upgrade customers to advanced metering infrastructure ("AMI"). NSPI will commence installation of AMI in 2019 and expects the project to be completed in 2020.

In 2018, NSPI expects to invest approximately $340 million (2017 - $392 million), including AFUDC, in capital projects. Capital will primarily be invested in projects which will support normal system reliability, with the decrease from 2017 driven by a reduction in information technology investments.

Emera Maine

Emera Maine is a transmission and distribution regulated electric utility in the State of Maine. Emera Maine's earnings are most directly impacted by the combined impacts of the range of rates of ROE and rate base approved by its regulators, the prudent management and approved recovery of operating costs, electric sales volumes (including the effects of weather), and the timing and amount of capital expenditures.

Emera Maine's 2018 earnings are expected to be generally consistent with prior years. Its ongoing investment in transmission and distribution infrastructure is expected to result in modest growth in rate base.

In June 2018, the MPUC approved a 5.3 per cent distribution rate increase. This increase was effective July 1, 2018 and is based on a 9.35 per cent ROE and a common equity component of 49 per cent. Prior to July 1, 2018, the allowed ROE was 9.0 per cent, on a common equity component of 49 per cent.

There are currently four pending complaints filed with the FERC to challenge the base ROE under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT"). On October 16, 2018, the FERC issued an order that addresses all four complaint proceedings. The FERC order proposes a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding is a 10.41 per cent base ROE for the ISO-NE OATT. Parties have 60 days to comment on the new methodology and its application to the four pending complaint proceedings. The current reserve is expected to be sufficient to cover the impact of this preliminary finding. For further discussion on the complaints, see note 18 to the condensed consolidated financial statements for Q3 2018.

In 2018, Emera Maine expects to invest approximately $75 million USD (2017 – $61 million USD) primarily on transmission and distribution capital projects.

Emera Caribbean

Emera Caribbean includes Emera (Caribbean) Incorporated (“ECI”) and its wholly owned subsidiaries BLPC, a vertically integrated regulated utility that is the provider of electricity in Barbados, and GBPC, a vertically integrated regulated utility and the sole provider of electricity on Grand Bahama Island. Emera Caribbean also includes:

- a 51.9 per cent interest in Domlec, a vertically integrated regulated 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.

On January 15, 2018, Emera completed the acquisition of the common shares held by the minority shareholders of ICD Utilities Limited (“ICDU”), increasing the Company’s interest in GBPC from 80.4 per cent to 100 per cent.

Earnings from Emera Caribbean are most directly impacted by rates of return on rate base approved by their regulators, capital structure, prudent management and approved recovery of operating costs, electric sales volumes and the timing and scale of capital expenditures.

Emera Caribbean’s 2018 earnings are expected to increase over the prior year. Earnings from GBPC are expected to increase due to lower OM&G and regulatory amortization as the utility continues to recover load after the short-term decline from Hurricane Matthew in 2016. Domlec is expecting a loss for 2018 consistent with 2017 as it completes its restoration efforts after Hurricane Maria. The increase at GBPC will be partially offset by lower earnings from BLPC due to accelerated depreciation and increased OM&G as the utility continues its grid modernization and transition to renewable, cleaner and more reliable generation.

On April 13, 2018, the Barbados Fair Trading Commission (“BTC”) approved BLPC’s application to recover the estimated $12 million USD in costs associated with the commissioning of a 5 MW battery storage system over a period of ten years. Recovery, including a return on capital, commenced through the fuel clause adjustment for an initial period of three years on September 1, 2018. In August 2018, the BTC approved BLPC’s application to review the heat rate targets specified in the approval of the recovery. The battery storage system is expected to enhance grid resilience, reliability and lower fuel costs to customers.

On June 6, 2018, S&P lowered its long-term foreign and local currency ratings on Barbados. This downgrade was driven by the Barbados government’s decision to suspend foreign currency debt repayments. On August 7, 2018, S&P lowered its long- and short-term local currency ratings and its ratings on certain global bonds. These downgrades are not expected to have a material impact on BLPC.

In 2018, Emera Caribbean plans to invest approximately $80 million USD (2017 - $54 million USD) in capital programs including increased spending on cleaner, more efficient, energy and grid modernization initiatives and restoration of the Domlec system. BLPC will invest in the installation of AMI meters and the commissioning of a battery storage system on the island of Barbados. GBPC will commence construction of its grid modernization battery storage project in late 2018, with final commissioning scheduled for early 2019.

Emera Energy

Emera Energy includes 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; 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.

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 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. In 2018, EES expects to earn near the high end of this range as a result of the favourable market conditions experienced to date.

Earnings from EEG’s assets are largely dependent on market conditions, in particular, the relative pricing of electricity and natural gas and the absolute price of natural gas as the marginal fuel in the supply stack, and capacity pricing in ISO-NE for NEGG. Efficient operations of the fleet to ensure unit availability, cost management, and effective commercial management are key success factors. EEG earnings are expected to be higher in 2018 as they benefit from higher capacity prices and fewer outage days, all other things being equal.

In 2018, Emera Energy expects to invest approximately $35 million (2017 – $47 million) in capital projects related to its generating assets to continue to improve reliability.

Corporate and Other

Corporate

Corporate encompasses 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-related costs and corporate human resource activities. It also includes interest revenue on intercompany financings recorded in “Intercompany revenue” and costs associated with corporate activities that are not directly allocated to the operations of Emera’s subsidiaries and investments.

Other

Other includes consolidated investments in Brunswick Pipeline, Emera Reinsurance Limited and Emera Utility Services Inc. It also includes non-consolidated investments in NSPML, LIL and M&NP. Investments in NSPML, LIL and M&NP are recorded as “Investments subject to significant influence” on Emera’s Condensed Consolidated Balance Sheets.

Corporate and Other’s contribution to consolidated net income is expected to be higher in 2018, primarily due to increased contributions from ENL (see below for further discussion on Maritime Link and Labrador Island Link) and higher tax recoveries. Tax recoveries are expected to be higher due to the non-cash tax expense recognized in 2017 as a result of US tax reform and remeasurement of certain deferred tax balances in 2018 resulting from a change in Florida state tax apportionment factors. This will be partially offset by increased interest expense due to the maturity of debt that had a favourable fair market value amortization in 2017 and lower income tax recoveries in 2018 as a result of the lower US federal corporate income tax rate.

In 2018, Corporate and Other, excluding companies accounted for as equity investments, expects to spend approximately $40 million (2017 - $21 million) on capital projects.

ENL

ENL holds equity investments in NSPML and LIL.

NSPML

The Maritime Link entered service on January 15, 2018. NSPML completed the project on time and within budget. Electricity is being transmitted between Newfoundland and Nova Scotia and the Maritime Link is providing service to electricity customers in both provinces. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. All major contracts have been concluded. NSPML's focus is on safely operating the Maritime Link in an efficient manner.

Future earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. The approved ROE is 9 per cent. Emera's equity earnings are expected to be higher in 2018 than in 2017 as the Maritime Link is now complete.

In 2018, NSPML expects to invest approximately $20 million in capital related to final construction costs.

LIL

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 $523 million, and is forecasted to be $534 million by the end of 2018, comprised of $410 million in equity contribution and an estimated $124 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $600 million by 2020 when all Lower Churchill projects, including Muskrat Falls, are forecasted by Nalcor Energy to be placed in service.

Construction of the LIL has been completed and the energization phase of the project began in June 2018. On June 27, 2018, Nalcor Energy recognized the first flow of energy from Labrador to Newfoundland and continues to work towards finalizing commissioning activities. Cash earnings and return of equity are forecasted by Nalcor Energy to begin in 2020 and until that point Emera will continue to record AFUDC earnings, with such earnings capitalized to its equity investment.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2017 and September 30, 2018 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Property, plant and equipment, net of accumulated depreciation and amortization	**$ 1,306**	Increased due to additions at regulated utilities, and the effect of a stronger USD on the translation of Emera's foreign subsidiaries, partially offset by increased accumulated depreciation.
Investments subject to significant influence	**86**	Increased due to investment in NSPML and LIL.
Goodwill	**185**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Receivables and other assets (current and long-term)	**(63)**	Decreased due to lower commodity prices and lower cash collateral positions at Emera Energy, partially offset by higher gas transportation assets at Emera Energy
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**498**	Increased due to the effect of a stronger USD on foreign currency debt, and increased borrowings under existing credit facilities. This was partially offset by net repayment of long-term debt at Emera Florida and New Mexico.
Derivative instruments (current and long-term)	**116**	Increased due to new contracts at Emera Energy, partially offset by the reversal of 2017 asset management agreement mark-to-market losses.
Regulatory liabilities (current and long-term)	**58**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and replenishment of the storm reserve at TEC.
Other liabilities (current and long-term)	**225**	Increased due to the timing of Emera's dividend payments and investment tax credits related to solar projects at TEC.
Common stock	**167**	Increased due to the dividend reinvestment plan and issuance of common stock for the purchase of additional shares of ICDU.
Cumulative preferred stock	**295**	Increased due to the issuance of preferred shares.
Accumulated other comprehensive income	**198**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Non-controlling interest in subsidiaries	**(52)**	Decreased due to increased ownership in GBPC.

DEVELOPMENTS

Increase in Common Dividend

Effective August 9, 2018, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.26 to $2.35. The first quarterly dividend payment at the increased rate is payable on November 15, 2018.

USGAAP Reporting Extension

On January 26, 2018, Emera was granted exemptive relief by Canadian securities regulators allowing Emera to continue to report its financial results in accordance with USGAAP (the “Exemptive Relief”). On July 18, 2018, Emera was granted an order pursuant to the *Companies Act* (Nova Scotia) exempting Emera from the *Companies Act* requirement to prepare its annual financial statements in accordance with International Financial Reporting Standards (“IFRS”) (the “Companies Act Relief”). Both the Exemptive Relief and the Companies Act Relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of the Company’s financial year commencing after the Company ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities. The Exemptive Relief and the Companies Act Relief each replace similar exemptive relief that had been previously granted to Emera in 2014 and would have expired by January 1, 2019.

Preferred Shares

On May 31, 2018, Emera issued 12 million Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share at an initial dividend rate of 4.9 per cent. The aggregate gross and net proceeds from the offering were $300 million and $295 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes. For further details, see note 19 to the condensed consolidated financial statements for Q3 2018.

On July 6, 2018, Emera announced it would not redeem the 10,000,000 Cumulative Rate Reset First Preferred Shares, Series C Shares. The holders of the Series C Shares had the right, at their option, to convert all or any of their Series C Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series D of the Company on August 15, 2018 or to continue to hold their Series C Shares. On August 8, 2018, Emera announced that after having taken into account all conversion notices received from holders, no First Preferred Shares, Series C Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series D Shares. For further discussion, see note 19 to the condensed consolidated financial statements for Q3 2018.

TEC Big Bend Power Station Modernization

On May 24, 2018, Tampa Electric announced its intention to invest approximately $850 million USD to modernize the Big Bend Power Station. This modernization project includes conversion of Unit 1 from coal-fired to natural gas combined-cycle technology and the early retirement of Unit 2. Construction has begun and is expected to be complete in 2023.

Tampa Electric Tax Reform and Storm Settlement

On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric that authorizes the utility to net the estimated amount of storm cost recovery against the return of estimated 2018 tax reform benefits to customers. Refer to the “Business Overview and Outlook”, “Emera Florida and New Mexico”, and “Emera Florida and New Mexico” sections for further details.

NSPML

The Maritime Link entered service on January 15, 2018, enabling the transmission of electricity between Newfoundland and Nova Scotia. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. Refer to the “Business Overview and Outlook”, “Corporate and Other - ENL” section for further details.

Appointments

Board of Directors
Effective July 10, 2018, James V. Bertram joined the Emera Board of Directors. Mr. Bertram is currently Chair of the Board, and former President and Chief Executive Officer, of Keyera Corporation, a publicly-traded, midstream oil and gas operator based in Calgary, Alberta.

Effective July 10, 2018, Jochen E. Tilk joined the Emera Board of Directors. Mr. Tilk is the former Executive Chair of Nutrien Inc., a Canadian global supplier of agricultural products and services based in Saskatoon, Saskatchewan. He is the former President and Chief Executive Officer of Potash Corporation of Saskatchewan.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars	
Balance, December 31, 2016	210.02	$	4,738
Conversion of Convertible Debentures	0.15		6
Issuance of common stock	14.61		680
Issued for cash under Purchase Plans at market rate	3.89		182
Discount on shares purchased under Dividend Reinvestment Plan	-		(9)
Options exercised under senior management stock option plan	0.10		3
Employee Share Purchase Plan	-		1
Balance, December 31, 2017	228.77	$	5,601
Conversion of Convertible Debentures (1)	0.01		-
Issuance of common stock (2)	0.45		22
Issued for cash under Purchase Plans at market rate	3.67		150
Discount on shares purchased under Dividend Reinvestment Plan	-		(7)
Options exercised under senior management stock option plan	0.02		1
Employee Share Purchase Plan	-		1
Balance, September 30, 2018	**232.92**	**$**	**5,768**

(1) As at September 30, 2018, a total of 52.15 million common shares of the Company were issued, representing conversion into common shares of more than 99.9 per cent of the Convertible Debentures.
(2) In Q1 2018, Emera issued 0.45 million common shares to facilitate the creation and issuance of 1.8 million depository receipts in connection with the ICDU share acquisition. The depository receipts are listed on the Bahamas International Securities Exchange.

As at October 25, 2018, the amount of issued and outstanding common shares was 233.0 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended September 30, 2018 was 233.7 million (2017 – 213.8 million) and for the nine months ended September 30, 2018 was 232.4 million (2017 – 212.7 million).

EMERA FLORIDA AND NEW MEXICO

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 592**	$ 596	**$ 1,560**	$ 1,578
Operating revenues – regulated gas	**144**	139	**553**	526
Operating revenues – non-regulated	**3**	3	**10**	9
Total operating revenues	**739**	738	**2,123**	2,113
Regulated fuel for generation and purchased power	**183**	181	**465**	491
Regulated cost of natural gas	**50**	57	**209**	208
Contribution to consolidated net income	**$ 108**	$ 95	**$ 254**	$ 232
Contribution to consolidated net income – CAD	**$ 140**	$ 120	**$ 327**	$ 302
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.60**	$ 0.56	**$ 1.41**	$ 1.42
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.30**	$ 1.26	**$ 1.29**	$ 1.30
EBITDA	**$ 284**	$ 298	**$ 754**	$ 808
EBITDA – CAD	**$ 370**	$ 374	**$ 971**	$ 1,054

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2017	**$ 95**	**$ 232**
Decreased electric operating revenues - see Operating Revenues - Regulated Electric below	(4)	(18)
Increased gas operating revenues - see Operating Revenues - Regulated Gas below	5	27
(Increased) decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(2)	26
Decreased (increased) cost of natural gas sold - see Regulated Cost of Natural Gas below	7	(1)
Increased OM&G expenses, primarily due to Tampa Electric's regulatory agreement to net storm costs and 2018 tax reform benefits resulting in storm costs recorded through OM&G with the offsetting tax reform benefits recorded through income tax expense	(25)	(85)
Increased depreciation and amortization due to asset growth and due to PGS's regulatory agreement to net amortization of its MGP environmental regulatory asset and 2018 tax reform benefits. The offsetting tax reform benefits were recorded through income tax expense	(11)	(21)
Increase in other income as the result of higher AFUDC earnings due to the construction of solar projects	8	5
Decreased income tax expense due to the reduction of the US federal corporate income tax rate, decreased income before provision for income taxes, and amortization of deferred income tax regulatory liabilities	33	85
Other	2	4
Contribution to consolidated net income – 2018	**$ 108**	**$ 254**

Emera Florida and New Mexico's CAD contribution to consolidated net income increased $20 million to $140 million in Q3 2018 from $120 million in Q3 2017 and year-to-date increased $25 million to $327 million, from $302 million in 2017. These increases were primarily due to higher AFUDC earnings and higher base rates as a result of the expansion of the Polk Power Station and completion of the first tranche of solar projects at Tampa Electric, partially offset by higher depreciation and amortization expense at Tampa Electric and PGS. The increased contribution year-to-date also included higher sales volumes from customer growth and favourable weather.

The impact of the change in the foreign exchange rate increased Q3 2018 CAD earnings by $6 million and decreased year-to-date CAD earnings by $3 million.

Emera Florida and New Mexico's contribution to consolidated net income is summarized in the following table:

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Tampa Electric	**$ 109**	$ 98	**$ 230**	$ 217
PGS	**9**	7	**36**	31
NMGC	**(4)**	(1)	**14**	12
Other (1)	**(6)**	(9)	**(26)**	(28)
Contribution to consolidated net income	**$ 108**	$ 95	**$ 254**	$ 232

(1) Other includes TECO Finance and administration costs.

Operating Revenues – Regulated Electric

Electric revenues decreased $4 million to $592 million in Q3 2018 compared to $596 million in Q3 2017. Year-to-date, electric revenues decreased $18 million to $1,560 million in 2018 compared to $1,578 million for the same period in 2017, primarily due to the timing of clause recoveries. This was partially offset by higher base revenues due to higher base rates related to the Polk Power Station expansion and solar projects, customer growth and favourable weather.

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

Q3 Electric Revenues

millions of US dollars	**2018**	2017
Residential	**$ 331**	$ 316
Commercial	**163**	159
Industrial	**43**	40
Other (1)	**55**	81
Total	**$ 592**	$ 596

(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	**2018**	2017
Residential	**$ 802**	$ 769
Commercial	**435**	439
Industrial	**121**	119
Other (1)	**202**	251
Total	**$ 1,560**	$ 1,578

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

Q3 Electric Sales Volumes

Gigawatt hours ("GWh")	**2018**	2017
Residential	**2,944**	2,861
Commercial	**1,791**	1,792
Industrial	**546**	522
Other	**526**	480
Total	**5,807**	5,655

YTD Electric Sales Volumes

GWh	**2018**	2017
Residential	**7,098**	6,916
Commercial	**4,698**	4,859
Industrial	**1,524**	1,530
Other	**1,447**	1,282
Total	**14,767**	14,587

Operating Revenues – Regulated Gas

Gas revenues increased $5 million to $144 million in Q3 2018 compared to $139 million in Q3 2017. Year-to-date, gas revenues increased $27 million to $553 million in 2018 compared to $526 million for the same period in 2017 due to higher clause recoveries and favourable customer growth and weather in Florida. This was partially offset by lower commodity costs in New Mexico.

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

Q3 Gas Revenues
millions of US dollars

		2018		2017
Residential	**$**	**57**	$	57
Commercial		**42**		45
Industrial (1)		**10**		9
Other (2)		**35**		28
Total	**$**	**144**	$	139

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

YTD Gas Revenues
millions of US dollars

		2018		2017
Residential	**$**	**265**	$	257
Commercial		**165**		160
Industrial (1)		**28**		26
Other (2)		**95**		83
Total	**$**	**553**	$	526

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

Q3 Gas Sales Volumes
Therms (millions)

	2018	2017
Residential	**34**	34
Commercial	**156**	153
Industrial	**367**	318
Other	**86**	93
Total	**643**	598

YTD Gas Sales Volumes
Therms (millions)

	2018	2017
Residential	**248**	231
Commercial	**581**	552
Industrial	**999**	924
Other	**197**	192
Total	**2,025**	1,899

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $2 million to $183 million in Q3 2018 compared to $181 million in Q3 2017. Year-to-date, regulated fuel for generation and purchased power decreased $26 million to $465 million in 2018 compared to $491 million for the same period in 2017 primarily due to a change in generation mix to lower cost natural gas from coal, oil and petcoke.

Q3 Production Volumes
GWh

	2018	2017
Natural gas	**4,698**	4,498
Coal	**775**	966
Oil and petcoke	**231**	160
Solar	**26**	12
Purchased power, net	**365**	347
Total production volumes	**6,095**	5,983

YTD Production Volumes
GWh

	2018	2017
Natural gas	**11,937**	10,262
Coal	**2,658**	4,244
Oil and petcoke	**472**	696
Solar	**50**	35
Purchased power	**727**	388
Total production volumes	**15,844**	15,625

Q3 Average Fuel Costs/Megawatt Hour ("MWh")
US dollars

		2018		2017
Dollars per MWh	**$**	**30**	$	30

YTD Average Fuel Costs/MWh
US dollars

		2018		2017
Dollars per MWh	**$**	**29**	$	31

Average fuel cost per MWh decreased year-to-date in 2018, compared to the same period in 2017, primarily due to a change in generation mix to lower cost natural gas.

Regulated Cost of Natural Gas

Regulated cost of natural gas decreased $7 million to $50 million in Q3 2018 compared to $57 million in Q3 2017 primarily due to lower commodity costs in New Mexico. Year-to-date, regulated cost of natural gas increased $1 million to $209 million in 2018 compared to $208 million for the same period in 2017.

Gas sales by type are summarized in the following table:

Q3 Gas Sales Volumes by Type
Therms (millions)

	2018	2017
System Supply	**127**	138
Transportation	**516**	460
Total	**643**	598

YTD Gas Sales Volumes by Type
Therms (millions)

	2018	2017
System Supply	**503**	477
Transportation	**1,522**	1,422
Total	**2,025**	1,899

NSPI

Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 310**	$ 283	**$ 1,055**	$ 983
Regulated fuel for generation and purchased power (1)	**148**	99	**460**	336
Contribution to consolidated net income	**$ 15**	$ 7	**$ 103**	$ 106
Contribution to consolidated earnings per common share – basic	**$ 0.06**	$ 0.03	**$ 0.44**	$ 0.50
EBITDA	**$ 103**	$ 93	**$ 372**	$ 362

(1) Regulated fuel for generation and purchased power includes the FAM on the Condensed Consolidated Income Statement, however it is excluded in the segment overview.

Net Income

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2017	**$ 7**	**$ 106**
Increased operating revenues - see Operating Revenues - Regulated Electric below	27	72
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(49)	(124)
Decreased FAM and fixed cost deferrals due to a current year net under-recovery of fuel costs compared to the prior year net over-recovery of fuel costs and the lower application of non-fuel revenues. Year-to-date was partially offset by the 2017 refund to customers of 2016 fuel costs	32	70
Increased OM&G expenses year-to-date mostly due to storm costs partially offset by higher administrative overhead allocated to property, plant and equipment	(2)	(12)
Increased depreciation and amortization due to increased property, plant and equipment	(3)	(8)
Other	3	(1)
Contribution to consolidated net income – 2018	**$ 15**	**$ 103**

NSPI's contribution to consolidated net income increased in Q3 2018 as a result of increased sales volume due to load growth and weather and decreased fixed cost deferral expense. Year-to-date, NSPI's contribution to consolidated net income decreased due to storm costs in the first quarter and increased depreciation expense, partially offset by increased sales volume due to load growth and decreased fixed cost deferral expense.

Operating Revenues – Regulated Electric

Operating revenues increased $27 million to $310 million in Q3 2018 compared to $283 million in Q3 2017, primarily due to increased sales volume due to load growth and weather. Year-to-date, operating revenues increased $72 million to $1,055 million in 2018 compared to $983 million for the same period in 2017, primarily due to the 2017 refund to customers of over-recovery of 2016 fuel costs, increased sales volume due to load growth and increased fuel-related electricity pricing effective January 1, 2018. This was partially offset by recovery of the reduced Maritime Link assessment to be returned to customers in 2019.

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

Q3 Electric Revenues
millions of Canadian dollars

		2018		2017
Residential	**$**	**139**	$	126
Commercial		**95**		91
Industrial		**60**		50
Other		**9**		9
Total	**$**	**303**	$	276

YTD Electric Revenues
millions of Canadian dollars

		2018		2017
Residential	**$**	**532**	$	501
Commercial		**298**		286
Industrial		**171**		144
Other		**33**		30
Total	**$**	**1,034**	$	961

Q3 Electric Sales Volumes
GWh

	2018	2017
Residential	**830**	784
Commercial	**739**	722
Industrial	**674**	615
Other	**63**	74
Total	**2,306**	2,195

YTD Electric Sales Volumes
GWh

	2018	2017
Residential	**3,322**	3,254
Commercial	**2,303**	2,289
Industrial	**1,942**	1,829
Other	**247**	260
Total	**7,814**	7,632

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $49 million to $148 million in Q3 2018 compared to $99 million in Q3 2017. Year-to-date, regulated fuel for generation and purchased power increased $124 million to $460 million in 2018 compared to $336 million for the same period in 2017. Changes in both periods were primarily due to the payment of the Maritime Link assessment, increased commodity prices and increased sales volumes.

Q3 Production Volumes
GWh

	2018	2017
Coal	**962**	986
Natural gas	**514**	477
Oil and petcoke	**238**	241
Purchased power – other	**217**	125
Total non-renewables	**1,931**	1,829
Purchased power – Independent Power Producers ("IPP")	**225**	220
Wind and hydro	**150**	168
Purchased power – Community Feed-in Tariff program ("COMFIT")	**101**	95
Biomass	**47**	20
Total renewables	**523**	503
Total production volumes	**2,454**	2,332

YTD Production Volumes
GWh

	2018	2017
Coal	**3,464**	3,671
Natural gas	**1,152**	1,095
Oil and petcoke	**992**	817
Purchased power – other	**365**	261
Total non-renewables	**5,973**	5,844
Purchased power – IPP	**906**	872
Wind and hydro	**884**	931
Purchased power – COMFIT	**400**	367
Biomass	**129**	100
Total renewables	**2,319**	2,270
Total production volumes	**8,292**	8,114

Q3 Average Fuel Costs

		2018		2017
Dollars per MWh produced	**$**	**60**	$	42

YTD Average Fuel Costs

		2018		2017
Dollars per MWh produced	**$**	**55**	$	41

Average fuel costs per MWh increased in Q3 2018 and year-to-date compared to the same periods in 2017, primarily due to payment of the Maritime Link assessment and increased commodity pricing.

NSPI's FAM regulatory liability balance has decreased $10 million from $177 million at December 31, 2017 to $167 million at September 30, 2018 primarily due to the net under-recovery of current period fuel costs and the refund to customers of the 2017 Maritime Link assessment. This was partially offset by the 2018 impact of the Maritime Link assessment and increased interest on the liability.

EMERA MAINE

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)		Three months ended September 30			Nine months ended September 30	
		2018	2017		**2018**	2017
Operating revenues – regulated electric	**$**	**56**	$ 59	**$**	**164**	$ 173
Regulated fuel for generation and purchased power (1)		**10**	18		**32**	47
Contribution to consolidated net income	**$**	**12**	$ 10	**$**	**25**	$ 29
Contribution to consolidated net income – CAD	**$**	**17**	$ 13	**$**	**33**	$ 38
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.07**	$ 0.06	**$**	**0.14**	$ 0.18
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.31**	$ 1.26	**$**	**1.29**	$ 1.30
EBITDA	**$**	**32**	$ 27	**$**	**82**	$ 84
EBITDA – CAD	**$**	**42**	$ 34	**$**	**106**	$ 110

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

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2017	**$ 10**	**$ 29**
Decreased operating revenues - see Operating Revenues - Regulated Electric below	(3)	(9)
Decreased regulated fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	8	15
Increased OM&G expenses year-to-date due to lower capitalized overheads as a result of lower capital spending, increased storm restoration work, higher medical costs, and regulatory adjustments related to the distribution rate case	-	(8)
Increased depreciation and amortization primarily due to increased regulatory amortization as a result of reduced purchase power contracts and higher plant in service	(5)	(12)
Decreased income tax expense due to the reduction of the US federal corporate income tax rate. Decreased income tax expense year-to-date is also due to decreased income before provision for income taxes	2	11
Other	-	(1)
Contribution to consolidated net income – 2018	**$ 12**	**$ 25**

Emera Maine's CAD contribution to consolidated net income increased $4 million to $17 million in Q3 2018 from $13 million in Q3 2017 and year-to-date decreased $5 million to $33 million in 2018 from $38 million during the same period in 2017. The year-to-date decrease was primarily due to increased OM&G and depreciation partially offset by decreased income tax expense. The foreign exchange rate had minimal impact for the three months and nine months ended September 30, 2018.

Operating Revenues – Regulated Electric

Operating revenues decreased $3 million to $56 million in Q3 2018 compared to $59 million in Q3 2017. Year-to-date, operating revenues decreased $9 million to $164 million in 2018 compared to $173 million for the same period in 2017 due to reduced transmission pool revenue primarily as a result of lower rates and lower stranded cost revenue mainly due to the expiration of a major purchased power contract. These decreases were partially offset by increased load due to favourable summer weather.

Emera Maine's operating revenues – regulated include sales of electricity and other services as summarized in the following table:

Q3 Operating Revenues – Regulated Electric
millions of US dollars

		2018		2017
Electric revenues	**$**	**43**	$	45
Transmission pool revenues		**12**		13
Resale of purchased power		**1**		1
Operating revenues – regulated electric	**$**	**56**	$	59

YTD Operating Revenues – Regulated Electric
millions of US dollars

		2018		2017
Electric revenues	**$**	**124**	$	128
Transmission pool revenues		**33**		38
Resale of purchased power		**7**		7
Operating revenues – regulated electric	**$**	**164**	$	173

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

Q3 Electric Revenues
millions of US dollars

		2018		2017
Residential	**$**	**20**	$	19
Commercial		**17**		15
Industrial		**4**		4
Other (1)		**2**		7
Total	**$**	**43**	$	45

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

YTD Electric Revenues
millions of US dollars

		2018		2017
Residential	**$**	**60**	$	60
Commercial		**46**		46
Industrial		**9**		10
Other (1)		**9**		12
Total	**$**	**124**	$	128

(1) Other revenue includes amounts recognized relating to FERC transmission rate refunds, tax reform refunds in 2018 and other transmission revenue adjustments.

Q3 Electric Sales Volumes
GWh

	2018	2017
Residential	**204**	188
Commercial	**201**	198
Industrial	**101**	97
Other	**3**	4
Total	**509**	487

YTD Electric Sales Volumes
GWh

	2018	2017
Residential	**609**	595
Commercial	**577**	579
Industrial	**265**	262
Other	**9**	11
Total	**1,460**	1,447

Regulated Fuel for Generation and Purchased Power

Emera Maine’s regulated fuel for generation and purchased power decreased $8 million to $10 million in Q3 2018 compared to $18 million in Q3 2017. Year-to-date, regulated fuel for generation and purchased power decreased $15 million to $32 million compared to $47 million for the same period in 2017 due to the expiration of a major purchased power contract.

EMERA CARIBBEAN

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)		Three months ended September 30				Nine months ended September 30		
		2018		2017		**2018**		2017
Operating revenues – regulated electric	**$**	**101**	$	87	**$**	**270**	$	250
Regulated fuel for generation and purchased power		**53**		39		**138**		111
Adjusted contribution to consolidated net income	**$**	**11**	$	9	**$**	**24**	$	23
Adjusted contribution to consolidated net income – CAD	**$**	**14**	$	12	**$**	**31**	$	30
After-tax equity securities mark-to-market gain (loss)		**1**		-		**(1)**		-
Contribution to consolidated net income	**$**	**12**	$	9	**$**	**23**	$	23
Contribution to consolidated net income – CAD	**$**	**14**	$	12	**$**	**29**	$	30
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$**	**0.06**	$	0.06	**$**	**0.13**	$	0.14
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.06**	$	0.06	**$**	**0.12**	$	0.14
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.31**	$	1.25	**$**	**1.30**	$	1.30
Adjusted EBITDA	**$**	**28**	$	28	**$**	**71**	$	76
Adjusted EBITDA – CAD	**$**	**36**	$	35	**$**	**91**	$	99

Net Income

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

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2017	**$**	**9**	$	**23**
Increased operating revenues - see Operating Revenues - Regulated Electric below		14		20
Increased regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below		(14)		(27)
Other		3		7
Contribution to consolidated net income – 2018	**$**	**12**	$	**23**

Emera Caribbean's CAD contribution to consolidated net income in Q3 2018 increased by $2 million to $14 million compared to $12 million in Q3 2017. Emera Caribbean's year-to-date CAD contribution decreased by $1 million to $29 million in 2018 compared to $30 million for the same period in 2017. The foreign exchange rate had minimal impact for the three and nine months ended September 30, 2018.

Operating Revenues – Regulated Electric

Operating revenues increased $14 million to $101 million in Q3 2018 compared to $87 million in Q3 2017 due to higher fuel prices in 2018 at BLPC. Year-to-date, operating revenues increased $20 million to $270 million in 2018 compared to $250 million for the same period in 2017. The increase was due to higher fuel prices in 2018 at BLPC, partially offset by lower sales volumes at Domlec due to the impact of Hurricane Maria.

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

Q3 Electric Revenues
millions of US dollars

		2018		2017
Residential	$	**34**	$	30
Commercial		**58**		49
Industrial		**5**		6
Other		**3**		2
Total	$	**100**	$	87

YTD Electric Revenues
millions of US dollars

		2018		2017
Residential	$	**89**	$	83
Commercial		**156**		142
Industrial		**17**		17
Other		**5**		5
Total	$	**267**	$	247

Q3 Electric Sales Volumes
GWh

	2018	2017
Residential	**123**	127
Commercial	**197**	197
Industrial	**22**	22
Other	**4**	5
Total	**346**	351

YTD Electric Sales Volumes
GWh

	2018	2017
Residential	**333**	353
Commercial	**562**	569
Industrial	**63**	65
Other	**11**	13
Total	**969**	1,000

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $14 million to $53 million in Q3 2018 compared to $39 million in Q3 2017 and year-to-date increased $27 million to $138 million in 2018 compared to $111 million for the same period in 2017 due to higher oil prices.

Q3 Production Volumes
GWh

	2018	2017
Oil	**355**	364
Hydro	**7**	6
Solar	**5**	3
Purchased power	**7**	5
Total	**374**	378

YTD Production Volumes
GWh

	2018	2017
Oil	**995**	1,032
Hydro	**17**	25
Solar	**13**	13
Purchased power	**19**	15
Total	**1,044**	1,085

Q3 Average Fuel Costs/MWh
US dollars

		2018		2017
Dollars per MWh	$	**142**	$	103

YTD Average Fuel Costs/MWh
US dollars

		2018		2017
Dollars per MWh	$	**132**	$	102

Average fuel cost per MWh increased in Q3 2018 and year-to-date in 2018, compared to the same periods in 2017, due to higher oil prices.

EMERA ENERGY

Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30				Nine months ended September 30			
		2018		2017		**2018**		2017
Marketing and trading margin (1) (2)	**$**	**6**	$	(4)	**$**	**73**	$	20
Electricity and capacity sales (3)		**106**		75		**313**		230
Total operating revenues – non-regulated		**112**		71		**386**		250
Non-regulated fuel for generation and purchased power (4)		**54**		42		**170**		149
Adjusted contribution to consolidated net income (loss)	**$**	**19**	$	(1)	**$**	**76**	$	(2)
After-tax derivative mark-to-market gain (loss)		**(73)**		(38)		**(22)**		105
Contribution to consolidated net income (loss)	**$**	**(54)**	$	(39)	**$**	**54**	$	103
Adjusted contribution to consolidated earnings per common share – basic	**$**	**0.08**	$	-	**$**	**0.33**	$	-
Contribution to consolidated earnings per common share – basic	**$**	**(0.23)**	$	(0.18)	**$**	**0.23**	$	0.48
Adjusted EBITDA								
Emera Energy Services	**$**	**1**	$	(9)	**$**	**52**	$	5
Emera Energy Generation		**35**		19		**91**		33
Equity Investment in Bear Swamp		**9**		4		**22**		8
Total	**$**	**45**	$	14	**$**	**165**	$	46

(1) Marketing and trading margin represents Emera Energy Service's purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market loss of $108 million in Q3 2018 (2017 - $56 million loss) and a loss of $71 million year-to-date in 2018 (2017 - $156 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market loss of $3 million in Q3 2018 (2017 - nil) and a gain of $28 million year-to-date in 2018 (2017 - $3 million loss).
(4) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $2 million in Q3 2018 (2017 - nil) and a gain of $5 million year-to-date in 2018 (2017 - $4 million loss).

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
Contribution to consolidated net income (loss) – 2017	**$**	**(39)**	**$**	**103**
Increased marketing and trading margin – see Emera Energy Services below		10		53
Increased electricity and capacity sales - see Emera Energy Generation below		31		83
Increased non-regulated fuel for generation and purchased power - see Emera Energy Generation below		(12)		(21)
Increased income tax expense due to increased income before provision for income taxes, partially offset by the reduction of the US federal corporate income tax rate		(7)		(36)
Increased mark-to-market loss, net of tax quarter-over-quarter primarily due to changes in existing positions, partially offset by lower amortization of gas transportation assets in Q3 2018. Year-over-year decreased mark-to-market gain, net of tax also due to change in existing positions on long-term natural gas contracts in 2017 and a larger reversal of mark-to-market losses in 2017 compared to 2018		(35)		(127)
Other		(2)		(1)
Contribution to consolidated net income (loss) – 2018	**$**	**(54)**	**$**	**54**

Excluding the change in mark-to-market, Emera Energy's contribution to consolidated net income increased quarter-over-quarter and year-to-date due to increased capacity prices and the favourable impact of warmer summer weather in 2018 across the Northeast on Emera Energy Services and Generation contributions. The year-to-date increase was also a result of the favourable impact of cold weather in early 2018 on Emera Energy Services contributions.

Emera Energy Services

Marketing and Trading Margin

Marketing and trading margin increased $10 million to $6 million in Q3 2018 compared to $(4) million in Q3 2017, reflecting stronger market conditions in Q3 2018 compared to Q3 2017, specifically the impact of warm summer weather in EES's key market areas.

Year-to-date marketing and trading margin increased $53 million to $73 million in 2018 compared to $20 million in 2017. In addition to the Q3 2018 explanation above, this increase is the result of the favourable impact of cold weather in early 2018 in several key market areas, which resulted in higher market prices and volatility that led to higher margins. The early 2018 activity also provided favourable hedging opportunities for the first quarter.

Emera Energy Generation

Q3 Electricity and Capacity Sales

For the millions of Canadian dollars						Three months ended September 30
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Electricity sales	**$ 66**	$ 44	**$ 2**	$ 5	**$ 68**	$ 49
Capacity sales	**38**	25	**-**	1	**38**	26
Electricity and capacity sales	**$ 104**	$ 69	**$ 2**	$ 6	**$ 106**	$ 75

Q3 Non-Regulated Fuel for Generation and Purchased Power

For the millions of Canadian dollars						Three months ended September 30
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Non-regulated fuel for generation and purchased power	**$ 50**	$ 36	**$ 3**	$ 4	**$ 53**	$ 40

YTD Electricity and Capacity Sales

For the millions of Canadian dollars						Nine months ended September 30
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Electricity sales	**$ 198**	$ 131	**$ 19**	$ 44	**$ 217**	$ 175
Capacity sales	**96**	53	**-**	2	**96**	55
Electricity and capacity sales	**$ 294**	$ 184	**$ 19**	$ 46	**$ 313**	$ 230

YTD Non-Regulated Fuel for Generation and Purchased Power

For the millions of Canadian dollars						Nine months ended September 30
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Non-regulated fuel for generation and purchased power	**$ 160**	$ 112	$ **9**	**$** 34	$ **169**	**$** 146

Emera Energy evaluates electricity sales and non-regulated fuel for generation and purchased power on a combined basis for its NEGG facilities because the sales price of electricity and the cost of natural gas used to generate it are highly correlated in that market. NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $16 million in Q3 2018, compared to $8 million in Q3 2017. This increase was due to more favourable market conditions, specifically the impact of warm summer weather that led to an increase in sales volumes and higher realized electricity pricing. Higher energy sales volumes in Q3 2018 also reflect a planned outage at Bridgeport Energy in Q3 2017.

Year-to-date, NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $38 million in 2018, compared to $19 million in 2017. In addition to the third quarter explanation above, this increase is due to the impact of an unplanned outage at Bridgeport Energy from mid-March 2017 to mid-June 2017 and higher realized electricity pricing in Q1 2018 compared to Q1 2017, reflecting more favourable winter market conditions.

Capacity sales increased $12 million to $38 million in Q3 2018 compared to $26 million in Q3 2017; and year-to-date increased $41 million to $96 million in 2018 compared to $55 million in 2017. These increases reflect higher capacity prices that came into effect for NEGG in June 2017 and June 2018.

The year-to-date reduction in electricity sales and non-regulated fuel for generation and purchased power in Maritime Canada in 2018, compared to 2017, reflected renegotiation of the Bayside Power PPA for the winter of 2017/2018, providing increased dispatch flexibility, while maintaining the net revenue stream for the facility.

Operating Statistics

For the	Three months ended September 30					
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2018	2017	**2018**	2017	**2018**	2017
New England	**1,549**	1,100	**96%**	92%	**63%**	45%
Maritime Canada	**30**	79	**97%**	87%	**4%**	11%
Total	**1,579**	1,179	**96%**	91%	**50%**	37%

For the	Nine months ended September 30					
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2018	2017	**2018**	2017	**2018**	2017
New England	**4,117**	2,496	**93%**	78%	**56%**	34%
Maritime Canada	**341**	660	**95%**	71%	**16%**	32%
Total	**4,458**	3,156	**94%**	76%	**47%**	34%

(1) Sales volumes represent the actual electricity output of the plants.
(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.
(3) Net capacity factor is the ratio of the utilization of an asset as compared to its maximum capability, within a particular time frame. It is generally a function of plant availability and plant economics vis-à-vis the market.

NEGG sales volumes, plant availability and net capacity factor were higher quarter-over-quarter reflecting a planned outage at the Bridgeport facility in Q3 2017 and favourable market conditions in Q3 2018. In addition to the third quarter explanation, year-over-year sales volumes, plant availability and net capacity factor were higher due to the impact of an unplanned outage at the Bridgeport facility from mid-March to mid-June 2017.

Maritime Canada plant availability was higher year-over-year due to a planned outage at the Bayside facility in Q2 2017. Sales volumes and capacity factor were lower due to the negotiated changes to Bayside Power's PPA for the 2017/2018 winter period.

CORPORATE AND OTHER

Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenues – regulated gas	**$ 15**	$ 14	**$ 41**	$ 39
Non-regulated operating revenue	**13**	21	**35**	56
Total operating revenue	**$ 28**	$ 35	**$ 76**	$ 95
Intercompany revenue (1)	**10**	10	**29**	29
Income from equity investments	**25**	25	**88**	70
Interest expense, net (2)	**76**	71	**226**	217
Adjusted contribution to consolidated net income (loss)	**$ (14)**	$ (33)	**$ (66)**	$ (87)
After-tax mark-to-market gain (loss)	**-**	1	**(1)**	2
Contribution to consolidated net income (loss)	**$ (14)**	$ (32)	**$ (67)**	$ (85)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.06)**	$ (0.15)	**$ (0.28)**	$ (0.41)
Contribution to consolidated earnings per common share – basic	**$ (0.06)**	$ (0.15)	**$ (0.29)**	$ (0.40)
Adjusted EBITDA	**$ 39**	$ 32	**$ 118**	$ 91

(1) Intercompany revenue consists of interest from Brunswick Pipeline, M&NP and EEG.

(2) Interest expense, net excludes a pre-tax mark-to-market of nil in Q3 2018 (2017 - $2 million gain) and a loss of $1 million year-to-date in 2018 (2017 – $3 million gain).

Net Income

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income (loss) – 2017	**$ (32)**	**$ (85)**
Decreased non-regulated operating revenue, with offsetting reduction in non-regulated direct costs, due to decreased project activity in Emera Utility Services	(8)	(21)
Increased income from equity investments due to contribution from NSPML - see Income from Equity Investments below	-	18
Decreased other non-regulated direct costs offsetting lower non-regulated operating revenue	6	22
Increased interest expense	(5)	(9)
Increased income tax recovery due to remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors. Year-to-date this was partially offset by decreased financing deductions and the reduction of the US federal corporate income tax rate	24	10
Other	1	(2)
Contribution to consolidated net income (loss) – 2018	**$ (14)**	**$ (67)**

Corporate and other's contribution to consolidated net income increased in Q3 2018 primarily due to increased income tax recovery offset by increased interest expense.

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
LIL	**$ 11**	$ 9	**$ 31**	$ 27
NSPML	**10**	10	**40**	26
M&NP	**4**	6	**17**	17
Income from equity investments	**$ 25**	$ 25	**$ 88**	$ 70

In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction.

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. 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.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2018 and 2017 include:

millions of Canadian dollars	**2018**	2017	Change
Cash, cash equivalents and restricted cash, beginning of period	**$ 503**	$ 491	$ 12
Provided by (used in):			
Operating cash flow before change in working capital	**1,237**	956	281
Change in working capital	**156**	85	71
Operating activities	**1,393**	1,041	352
Investing activities	**(1,565)**	(1,273)	(292)
Financing activities	**121**	62	59
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**11**	(21)	32
Cash, cash equivalents and restricted cash, end of period	**$ 463**	$ 300	$ 163

Cash Flow from Operating Activities

Net cash provided by operating activities year-to-date in 2018 increased $352 million to $1,393 million compared to $1,041 million for the same period in 2017.

Cash from operations before changes in working capital increased $281 million. This was due to lower under-recovery from customers on clause related costs in 2018 than 2017 and lower pension contributions in 2018 at Emera Florida and New Mexico, increased capacity payments at NEGG, and increased marketing and trading margin at EES. These were partially offset by increased fuel for generation and purchased power at NSPI.

Changes in working capital increased operating cash flows by $71 million. This increase was mainly due to favourable changes in cash collateral at Emera Energy and favourable changes in accounts receivable and accounts payable at Emera Florida and New Mexico. These were partially offset by unfavourable changes in other current liabilities at Emera Florida and New Mexico and NEGG.

Cash Flow used in Investing Activities

Net cash used in investing activities increased $292 million to $1,565 million for the nine months ended September 30, 2018 compared to $1,273 million for the same period in 2017 due to an increase in capital expenditures, partially offset by reduced equity contributions in NSPML and LIL in 2018 compared to 2017.

Capital expenditures for the nine months ended September 30, 2018, including AFUDC and net of proceeds from disposal of assets, were $1,556 million compared to $1,091 million for the same period in 2017. Details of the year-to-date 2018 capital spend are shown below:

- $1,135 million at Emera Florida and New Mexico (2017 – $645 million);
- $251 million at NSPI (2017 – $276 million);
- $62 million at Emera Maine (2017 – $77 million);
- $58 million at Emera Caribbean (2017 – $39 million);
- $18 million at Emera Energy (2017 – $34 million); and
- $32 million in Corporate and Other (2017 – $20 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $59 million to $121 million for the nine months ended September 30, 2018 compared to $62 million for the same period in 2017. The increase was due to the issuance of preferred stock in 2018, partially offset by decreased borrowings under Emera's committed credit facilities in 2018, a net repayment of long-term debt at Emera Florida and New Mexico and increased 2018 dividends on common stock.

Contractual Obligations

As at September 30, 2018, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt principal	$ 22	$ 1,077	$ 787	$ 2,273	$ 483	$ 9,938	$ 14,580
Interest payment obligations (1)	248	643	596	538	495	6,396	8,916
Purchased power (2)	62	220	218	223	223	2,386	3,332
Transportation (3)	127	397	314	208	193	1,566	2,805
Pension and post-retirement obligations (4)	15	63	64	65	66	805	1,078
Capital projects	286	326	143	32	3	3	793
Fuel and gas supply	155	297	88	46	6	3	595
Long-term service agreements (5)	24	91	51	50	39	278	533
Asset retirement obligations	1	1	1	43	1	382	429
Equity investment commitments (6)	-	-	190	-	-	-	190
Leases and other (7)	33	18	15	10	8	71	155
Demand side management	11	12	1	-	-	-	24
Long-term payable	1	4	5	5	5	5	25
Convertible debentures	-	-	-	-	-	3	3
	$ 985	$ 3,149	$ 2,473	$ 3,493	$ 1,522	$ 21,836	$ 33,458

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at September 30, 2018, including any expected required payment under associated swap agreements.
(2) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(4) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2017. Credited service and earnings are assumed to be crystallized as at December 31, 2017. 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, 2017 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.
(5) 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.
(6) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(7) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. The UARB has approved NSPI to pay NSPML approximately $110 million and $111 million in 2018 and 2019, respectively. After 2019, the timing and amounts payable to NSPML will be subject to a regulatory filing with the UARB which will be filed no later than 2019.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.4 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 – Operating and acquisition credit facility	June 2020 – Revolver	$ 900	$ 324	$ 576
Emera Florida and New Mexico - in USD - credit facilities	November 2018 - March 2022	1,800	1,166	634
NSPI – Operating credit facility	October 2021 – Revolver	600	383	217
Emera Maine – in USD – Operating credit facility	February 2023 – Revolver	80	59	21
Other – in USD – Operating credit facilities	Various	32	13	19

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at September 30, 2018.

Recent financing activities for Emera and its subsidiaries are discussed below.

Emera

On May 31, 2018, Emera issued 12 million 4.90 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share for gross proceeds of $300 million and net proceeds of $295 million. The net proceeds of the preferred share offering were used for general corporate purposes. For further details, see note 19 to the condensed consolidated financial statements for Q3 2018. The offering was made under Emera's $750 million short form base shelf prospectus dated May 16, 2018. As at September 30, 2018 the Company has $450 million available for issuance under this prospectus, which expires on June 16, 2020.

Emera Florida and New Mexico

On October 4, 2018, TEC completed a $375 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.45 per cent and have a maturity date of June 15, 2049. On October 11, 2018 proceeds from this issuance were used to repay a $300 million USD 1-year term credit facility. This credit facility was classified as long-term debt at September 30, 2018.

On June 7, 2018, TEC completed a $350 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.30 per cent and have a maturity date of June 15, 2048.

On April 10, 2018, TECO Energy/Finance repaid a $250 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

On March 23, 2018, TEC extended the maturity date of its $150 million USD accounts receivable collateralized borrowing facility from March 23, 2018 to March 22, 2021. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $300 million USD revolving credit facility by $100 million USD to $400 million USD. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $400 million USD term bank credit facility by $100 million USD to $500 million USD, and extended the maturity date from March 8, 2018 to March 8, 2019. There were no other changes in commercial terms.

Emera Maine

On February 28, 2018, Emera Maine extended the maturity date of its $80 million USD operating credit facility from September 25, 2019 to February 28, 2023. There were no other changes in commercial terms.

ECI

On January 12, 2018, a wholly owned indirect subsidiary of ECI entered into a five year $18 million Bahamian dollar loan agreement with an interest rate of 4.00 per cent and maturity date of January 12, 2023.

Guarantees and Letters of Credit

As at September 30, 2018, Emera had several significant guarantees and letters of credit on behalf of third parties outstanding. The following guarantees and letters of credit are not included within the Condensed Consolidated Balance Sheets as at September 30, 2018:

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

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian was obligated to file, in respect of each mining permit, applications in connection with the change of control with the appropriate governmental entities. As each application was approved, Cambrian was required to post a bond or other appropriate collateral in order to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. In April 2018, all of the TECO Coal bonds were released and returned.

Emera has standby letters of credit in the amount of $48 million USD to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in February 2019 and is renewed annually. The amount committed as of September 30, 2018 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under an unfunded pension plan. The letter of credit expires in June 2019 and is renewed annually. The amount committed as at September 30, 2018 was $49 million CAD.

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 Operating expenses, Regulated fuel for generation and purchased power, totalling $25 million for the three months ended September 30, 2018 (2017 – nil) and $76 million for the nine months ended September 30, 2018 (2017 - nil). 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", "Corporate and Other – 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 $6 million for the three months ended September 30, 2018 (2017 - $4 million) and $22 million for the nine months ended September 30, 2018 (2017 - $20 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2018 and at December 31, 2017.

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 2017 annual MD&A.

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Derivative instrument assets (current and other assets)	**$ 1**	$ 7
Derivative instrument liabilities (current and long-term liabilities)	**(3)**	(7)
Net derivative instrument assets (liabilities)	**$ (2)**	$ -

Hedging Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenues – regulated	**$ 1**	$ (1)	**$ 5**	$ (7)
Non-regulated fuel for generation and purchased power	**(1)**	-	**2**	3
Effective net gains (losses)	**$ -**	$ (1)	**$ 7**	$ (4)

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

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Derivative instrument assets (current and other assets)	**$ 176**	$ 181
Regulatory assets (current and other assets)	**9**	13
Derivative instrument liabilities (current and long-term liabilities)	**(9)**	(13)
Regulatory liabilities (current and long-term liabilities)	**(181)**	(183)
Net asset (liability)	**$ (5)**	$ (2)

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Regulated fuel for generation and purchased power (1)	**$ 6**	$ 1	**$ 11**	$ 14
Net gains (losses)	**$ 6**	$ 1	**$ 11**	$ 14

(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 or property plant and equipment will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

HFT Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Derivative instruments assets (current and other assets)	**$ 71**	$ 63
Derivative instruments liabilities (current and long-term liabilities)	**(414)**	(290)
Net derivative instrument assets (liabilities)	**$ (343)**	$ (227)

HFT Items Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenue - non-regulated	**$ (105)**	$ 26	**$ 44**	$ 409
Non-regulated fuel for purchased power	**2**	(1)	**2**	6
Net gains (losses)	**$ (103)**	$ 25	**$ 46**	$ 415

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Derivative instrument assets (current and other assets)	**$ 1**	$ 2
Net derivative instrument assets (liabilities)	**$ 1**	$ 2

Other Derivatives Recognized in Net Income

The Company has realized and unrealized gains (losses) with respect to cash flow hedges for which documentation requirements have not been met for the three months ended September 30, 2018 of nil (2017 - $2 million) and for the nine months ended September 30, 2018 of nil (2017 - $3 million).

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”). The Company’s internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations (“COSO”) of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design of the Company’s DC&P and ICFR as at September 30, 2018, to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

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

There were no changes in the Company’s ICFR during the quarter ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

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

Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, capitalized overhead and valuation of financial instruments. Actual results may differ significantly from these estimates. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in the Company's 2017 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2018, are described as follows:

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income
In February 2018, the FASB issued Accounting Standard Updates ("ASU") No. 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The standard allows reclassification from accumulated other comprehensive income to retained earnings for certain tax effects resulting from the US Tax Cuts and Jobs Act that would otherwise be stranded in accumulated other comprehensive income. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted. The Company early adopted the standard in June 2018 and elected to not reclassify tax effects resulting from the US Tax Cuts and Jobs Act stranded in accumulated other comprehensive income to retained earnings as amounts were not material. Emera utilizes a portfolio approach to determine the timing and extent to which stranded income tax effects from items that were previously recorded in accumulated other comprehensive income are released.

Revenue from Contracts with Customers
On January 1, 2018, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers* and all the related amendments, which created a new, principle-based revenue recognition framework. The standard has been codified as Accounting Standards Codification ("ASC") Topic 606. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled to. The guidance requires additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company adopted ASC 606 using the modified retrospective method. Results for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting practices. The adoption of ASC 606 resulted in no adjustments to the Company's opening retained earnings as of the adoption date. The impact of the adoption of the new standard was immaterial to the Company's net income and is expected to be immaterial on an ongoing basis.

Recognition and Measurement of Financial Assets and Financial Liabilities
On January 1, 2018, the Company adopted ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities* and all the related amendments. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The standard requires investments in equity securities, except those accounted for under the equity method of accounting or those that result in consolidation, to be measured at fair value. The Company has elected to measure equity securities that do not have a readily determinable fair value at cost minus impairment (if any), plus or minus observable price changes resulting from transactions for the identical or a similar investment of the same issuer. The standard eliminates the available-for-sale classification for equity investments that recognized changes in the fair value as a component of other comprehensive income, resulting in all changes in fair value being recognized in net income. The impact as a result of the remeasurement of equity investments is expected to be immaterial to the Company's net income on an ongoing basis. A cumulative-effect adjustment of $4 million was made to retained earnings in the Condensed Consolidated Balance Sheet as of January 1, 2018.

Clarifying the Definition of a Business
In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and is required to be applied prospectively. The Company adopted ASU 2017-01 effective January 1, 2018. There was no impact on the condensed consolidated financial statements as a result of the adoption of this standard.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* The guidance requires the service cost component of defined benefit pension or other postretirement benefit plans to be reported in the same line items as other compensation costs. The other components of net benefit cost are required to be presented in the Condensed Consolidated Statements of Income outside of income from operations. Only the service cost component is eligible for capitalization as property, plant and equipment under this guidance. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The guidance is required to be applied retrospectively for presentation in the Condensed Consolidated Statements of Income and prospectively for the guidance around capitalization.

The Company adopted ASU 2017-07 effective January 1, 2018 and September 30, 2017 balances have been retrospectively restated in the Condensed Consolidated Statements of Income. The standard allows the Company to use the amounts disclosed in its pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements. This change resulted in $7 million and $21 million of costs, previously presented within "Operating, maintenance and general", being reclassified to "Other income (expense), net" in the Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2017.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by Financial Accounting Standards Board (the "FASB"). The ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the 2017 audited consolidated financial statements, with updates noted below.

Leases
In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as assets and liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted and is required to be applied using a modified retrospective approach. The Company will not early adopt the standard.

In January 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The Company will make this election. In July 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The Company will make this election. Additionally, the Company will elect the option that allows the Company to not reassess whether any expired or existing contracts contain leases and will carry forward existing lease classification.

The standard will affect the Company’s financial position by increasing the assets and liabilities recorded relating to its operating leases, however, the ultimate impact of the new standard on the Company’s financial statements and disclosures has not yet been fully determined. In 2017, the Company developed and began execution of a project plan, which included holding training sessions with key stakeholders throughout the organization and gathering detailed information on existing lease arrangements. Activities currently being executed include evaluating the remaining available implementation alternatives, calculating the lease asset and liability balances associated with individual contractual arrangements and assessing the disclosure requirements. The Company will implement additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There will not be significant updates to systems as a result of implementation. The Company continues to monitor FASB amendments to ASC Topic 842.

Cloud Computing
In August 2018, the 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 will be 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 is currently evaluating the transition methods and the impact of the adoption of this standard on the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q3 2018**	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Operating revenues	**$ 1,495**	$ 1,423	$ 1,807	$ 1,473	$ 1,427	$ 1,469	$ 1,857	$ 1,513
Net income (loss) attributable to common shareholders	**118**	90	271	(228)	81	101	312	70
Adjusted net income attributable to common shareholders	**191**	111	202	137	118	117	152	104
Earnings per common share – basic	**0.51**	0.38	1.17	(1.06)	0.38	0.47	1.48	0.34
Earnings per common share – diluted	**0.50**	0.38	1.17	(1.06)	0.38	0.47	1.47	0.34
Adjusted earnings per common share – basic	**0.82**	0.48	0.87	0.64	0.55	0.55	0.72	0.51

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 and mark-to-market