Management’s Discussion & Analysis

As at November 10, 2017

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 in 2017 relative to the same periods in 2016; and its financial position as at September 30, 2017 relative to December 31, 2016. To enhance shareholders’ understanding, certain multi-year historical financial and statistical information is presented. 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, 2017; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2016. 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
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 Investment	
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
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 which 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; enterprise resource planning ("ERP") system 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; project development and construction 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, gas transmission and distribution, and utility services, predominantly within rate-regulated utilities supporting 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 targets eight per cent annual dividend growth through 2020.

Emera targets achieving a minimum of 75 per cent of its adjusted net income from its rate-regulated utilities, which is reflective of the Company's low risk profile; and an average dividend payout ratio of 70 to 75 per cent of adjusted net income.

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 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.

While it is still unclear whether economic volatility, government policy and lower fossil fuel prices will slow the pace of change, an impact on the sector continues to be felt in the form of mandated and incented carbon reductions throughout eastern North America and in the Caribbean. As such, investment in wind, solar, and hydro generation, natural gas and new transmission infrastructure is likely to continue across the sector despite any 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 evaluating and investing in a number of initiatives, including transmission and solar generation, that would reduce carbon emissions. NSPI 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 ownership in the Maritime Link Project 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 component of Emera's business that is not rate-regulated. Formed in 2003, 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 northeast North America, and the business is supported by comprehensive infrastructure and market knowledge, a focus on customer service and robust risk management.

A collaborative approach to strategic partnerships, combined with the ability to find creative solutions to work within and across multiple jurisdictions, and experience dealing with complex projects and investment structures are fundamental to Emera's strategy. 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, constructive regulatory approaches, and proactive stakeholder engagement.

Emera has grown its asset base to deliver on its strategic objectives. Over the last 10 years, Emera's ability to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. In addition to access to debt and equity capital markets, cash flow from operations will continue to play a role in financing the Company's future growth. Maintaining strong, investment grade credit ratings is an important component of Emera's financing 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.

NON-GAAP FINANCIAL MEASURES

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

Adjusted Net Income

Emera calculates an adjusted net income measure by excluding the effect of:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company LLC ("Bear Swamp");
- the amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline; and
- the mark-to-market adjustments included in Emera's other income in 2016 related to the effect of USD-denominated currency and forward contracts for the TECO Energy, Inc. ("TECO Energy") acquisition. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures").

Management believes excluding from 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 use this non-GAAP measure for evaluation of performance and incentive compensation.

Mark-to-market adjustments are further discussed in the Consolidated Financial Review section, Emera Energy and Corporate and Other.

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	
	2017	2016	**2017**	2016
Net income attributable to common shareholders	**$ 81**	$ (95)	**$ 494**	$ 157
After-tax mark-to-market gain (loss)	**$ (37)**	$ (109)	**$ 107**	$ (214)
Adjusted net income attributable to common shareholders	**$ 118**	$ 14	**$ 387**	$ 371
Earnings per common share – basic	**$ 0.38**	$ (0.52)	**$ 2.32**	$ 0.98
Adjusted earnings per common share – basic	**$ 0.55**	$ 0.08	**$ 1.82**	$ 2.31

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 reflects 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.

EBITDA and Adjusted EBITDA are discussed further in the Consolidated Financial Review, Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy, and Corporate and Other sections.

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	
	2017	2016	**2017**	2016
Net income (1)	**$ 99**	$ (76)	**$ 531**	$ 195
Interest expense, net	**170**	233	**523**	416
Income tax expense	**45**	(44)	**191**	(16)
Depreciation and amortization	**207**	204	**644**	376
EBITDA	**521**	317	**1,889**	971
Mark-to-market gain (loss), excluding income tax and interest	**(54)**	(158)	**153**	(275)
Adjusted EBITDA	**$ 575**	$ 475	**$ 1,736**	$ 1,246

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Q3 Earnings

2017

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

After-tax mark-to-market losses decreased $72 million to $37 million in Q3 2017 compared to $109 million in Q3 2016 mainly due to changes in existing positions on long-term natural gas contracts at Emera Energy. Year-to-date, after-tax mark-to-market increased $321 million to a $107 million gain in 2017 compared to a $214 million loss for the same period in 2016. 2016 year-to-date included a $116 million loss resulting from the reversal of 2015 gains on USD-denominated currency and forward contracts related to the financing of the TECO Energy acquisition. Other factors contributing to the increase include changes in existing positions on long-term contracts at Emera Energy, and the reversal of 2016 mark-to-market losses at Emera Energy.

2016

Acquisition Related Costs

Emera incurred after-tax costs of $119 million ($0.65 per common share) in Q3 2016 and $179 million year-to-date in 2016 ($1.12 per common share) related to its acquisition of TECO Energy. All acquisition costs were recognized in the Corporate and Other segment.

Investment in Algonquin Power and Utilities Corp.

On May 24, 2016, Emera completed the sale of 50.1 million common shares of Algonquin Power and Utilities Corp. ("APUC"), representing approximately 19.3 per cent of APUC's issued and outstanding common shares, for gross proceeds of $544 million. This sale resulted in a pre-tax gain of $172 million or $1.15 per common share (after-tax gain of $146 million or $0.97 per common share), which was recorded in "Other income (expenses), net" in Q2 2016.

On June 30, 2016, Emera exchanged 12.9 million APUC subscription receipts and dividend equivalents into 12.9 million APUC common shares. This conversion resulted in a pre-tax gain of $63 million or $0.42 per common share (after-tax gain of $53 million or $0.35 per common share), which was recorded in "Other income (expenses), net" in Q2 2016. These shares were sold on December 8, 2016. Emera no longer holds any interest in APUC.

Gain on BLPC Self-Insurance Fund Regulatory Liability

BLPC maintains a Self-Insurance Fund ("SIF") for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. Third party risk advisors were engaged to support a detailed risk analysis, which was completed to quantify the prudent assessment of the risk to BLPC's transmission and distribution system from natural catastrophes.

In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $29 million ($22 million USD). As a result, Emera recorded a pre-tax gain of $53 million ($41 million USD) or $0.35 per common share and an after-tax gain of $43 million ($34 million USD) or $0.29 per common share in "Other income (expenses), net". In Q3 2016, Emera received a distribution of $65 million ($50 million USD) from the fund.

Emera Energy Recognition of State Fuel Taxes

In Q2 2016, Emera Energy recorded a $20 million pre-tax or $0.13 per common share ($12 million after-tax or $0.08 per common share) liability for state tax on natural gas sales made from November 2013 through March 2016, including $4 million pre-tax ($2 million after-tax) related to Q1 2016. The recognition of this liability resulted in an increase to "Non-regulated fuel for generation and purchased power".

Consolidated Financial Highlights

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
Adjusted Net Income	**2017**	2016	**2017**	2016
Emera Florida and New Mexico	**$ 120**	$ 109	**$ 302**	$ 109
NSPI	**7**	15	**106**	96
Emera Maine	**13**	17	**38**	36
Emera Caribbean	**12**	24	**30**	92
Emera Energy	**(1)**	-	**(2)**	19
Corporate and Other	**(33)**	(151)	**(87)**	19
Adjusted net income attributable to common shareholders	**$ 118**	$ 14	**$ 387**	$ 371
After-tax mark-to-market gain (loss)	**(37)**	(109)	**107**	(214)
Net income (loss) attributable to common shareholders	**$ 81**	$ (95)	**$ 494**	$ 157

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Operating revenues	**$ 1,427**	$ 1,387	**$ 4,753**	$ 2,764
Income from operations	**283**	76	**1,155**	347
Net income (loss) attributable to common shareholders	**81**	(95)	**494**	157
After-tax mark-to-market gain (loss)	**(37)**	(109)	**107**	(214)
Adjusted net income attributable to common shareholders	**$ 118**	$ 14	**$ 387**	$ 371
Earnings per common share – basic	**$ 0.38**	$ (0.52)	**$ 2.32**	$ 0.98
Earnings per common share – diluted	**$ 0.38**	$ (0.52)	**$ 2.31**	$ 0.97
Adjusted earnings per common share – basic	**$ 0.55**	$ 0.08	**$ 1.82**	$ 2.31
Dividends per common share declared	**$ 1.0875**	$ 1.0450	**$ 2.1325**	$ 1.9950
Adjusted EBITDA	**$ 575**	$ 475	**$ 1,736**	$ 1,246

The following table highlights significant changes in adjusted net income from 2016 to 2017.

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2016	**$ 14**	**$ 371**
2016 acquisition and financing costs related to the acquisition of TECO Energy	119	179
Emera Florida and New Mexico	11	193
NSPML and LIL AFUDC earnings	7	22
TECO Energy post-acquisition financing costs	6	(84)
Emera Energy	(1)	(33)
NSPI	(8)	10
Emera Caribbean	(12)	(19)
2016 Emera Energy's recognition of fuel taxes for 2013 to March 2016	-	12
2016 gain on BLPC SIF regulatory liability	-	(43)
2016 gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	-	(53)
2016 gain on sale of APUC common shares	-	(146)
APUC equity earnings - sold in 2016	-	(18)
Other	(18)	(4)
Adjusted net income – 2017	**$ 118**	**$ 387**

For the millions of Canadian dollars	Nine months ended September 30 **2017**	 2016
Operating cash flow before changes in working capital	**$ 956**	$ 615
Change in working capital	**85**	252
Operating cash flow	**$ 1,041**	$ 867
Investing cash flow	**$ (1,271)**	$ (8,607)
Financing cash flow	**$ 62**	$ 7,157

As at millions of Canadian dollars	**September 30 2017**	December 31 2016
Working capital	**$ (9)**	$ 301
Total assets	**$ 27,882**	$ 29,221
Total long-term debt (including current portion)	**$ 14,161**	$ 14,744

Q3 Consolidated Income Statement Highlights

Operational Results

Income from operations increased $207 million to $283 million in Q3 2017 compared to $76 million in Q3 2016. Absent mark-to-market gains of $102 million, income from operations increased $105 million due to 2016 costs related to the TECO Energy acquisition and increased contribution from Emera Florida and New Mexico.

Total operating revenues increased $40 million to $1,427 million in Q3 2017 compared to $1,387 million in Q3 2016. Absent mark-to-market increases of $99 million, operating revenues decreased $59 million due to:

- $31 million decrease from Emera Florida and New Mexico due to the impact of a strengthening CAD. This decrease was partially offset by increased revenues at Tampa Electric reflecting higher base rate revenue offset by lower sales volumes and lower clause related revenue;
- $19 million decrease from Emera Energy Generation ("EEG") reflecting decreased sales volumes driven by less favourable market conditions and lower power prices, partially offset by higher capacity revenue.

Total operating expenses decreased $167 million to $1,144 million in Q3 2017 compared to $1,311 million in Q3 2016, due to 2016 expenses related to the acquisition of TECO Energy and decreased fuel expense at Tampa Electric and EEG reflecting lower sales volumes.

Interest expense, net

Interest expense, net decreased $63 million in Q3 2017 to $170 million compared to $233 million in the same period in 2016 due to interest costs associated with the TECO Energy related Debentures in Q3 2016.

Income tax expense

Income tax expense increased $89 million to $45 million in Q3 2017 compared to a $44 million income tax recovery in Q3 2016 due to increased income before provision for income taxes.

Year-to-Date Consolidated Income Statement and Operating Cash Flow Highlights

Operational Results

Income from operations increased $808 million to $1,155 million year-to-date in 2017 compared to $347 million for the same period in 2016. Absent mark-to-market increases of $290 million, income from operations increased $518 million mainly due to the contribution of Emera Florida and New Mexico and the 2016 costs related to the acquisition of TECO Energy, partially offset by decreased contribution from Emera Energy.

Total operating revenues increased $1,989 million to $4,753 million year-to-date in 2017 compared to $2,764 million in 2016. Absent mark-to-market increases of $298 million, operating revenues increased $1,691 million due to:

- $1,800 million increase from Emera Florida and New Mexico;
- $121 million decrease at EEG reflecting lower hedged power prices in Q1 2017 compared to Q1 2016, decreased sales volumes driven by less favourable market conditions, and an unplanned outage at the Bridgeport Facility. This decrease was partially offset by higher capacity revenue.

Total operating expenses increased $1,181 million to $3,598 million year-to-date in 2017 compared to $2,417 million for the same period in 2016 due to:

- $1,349 million addition of expenses from Emera Florida and New Mexico;
- $101 million decrease in fuel expense at EEG due to decreased volumes reflecting less favourable market conditions and an unplanned outage at the Bridgeport Facility, lower hedged natural gas prices in Q1 2017 compared to Q1 2016, and the recognition of prior period state fuel taxes in Q2 2016;
- $88 million decrease related to the 2016 TECO Energy acquisition costs.

Other income (expenses), net

Other income decreased $169 million to nil year-to-date in 2017 compared to $169 million for the same period in 2016. This was due to a $172 million gain on the 2016 sale of APUC common shares, a $63 million gain on the 2016 conversion of APUC subscription receipts and dividend equivalents into common shares, and a $53 million gain on the BLPC SIF regulatory liability in 2016. These 2016 gains were partially offset by $116 million of mark-to-market losses in 2016 relating to the TECO Energy acquisition related USD-denominated currency and forward contracts.

Interest expense, net

Interest expense, net increased $107 million year-to-date in 2017 to $523 million compared to $416 million in 2016. This was due to interest expense from Emera Florida and New Mexico and financing related to the TECO Energy acquisition, partially offset by the interest costs associated with the TECO Energy related Debentures in Q3 2016.

Income tax expense

Income tax expense increased $207 million to $191 million year-to-date compared to a $16 million income tax recovery for the same period in 2016 primarily due to increased income before provision for income taxes, the non-taxable portion of gains on the 2016 APUC transactions and changes in the proportion of income earned in foreign jurisdictions. This was partially offset by the non-deductible portion of foreign exchange and mark-to-market adjustments related to the TECO Energy acquisition in 2016.

Net cash provided by operating activities

Net cash provided by operating activities in 2017 increased $174 million to $1,041 million compared to $867 million during the same period in 2016.

Cash from operations before changes in working capital increased $341 million mainly due to the contribution from Emera Florida and New Mexico and acquisition and financing costs related to the TECO Energy acquisition in 2016, partially offset by increased financing costs in 2017 and decreased margin from Emera Energy Services (“EES”) and New England Gas Generating Facilities (“NEGG”).

Changes in working capital decreased operating cash flows by $167 million. This decrease was due to timing of receivables collection at TEC as a result of Hurricane Irma, an increased cash collateral position on derivative instruments and changes in inventory levels compared to 2016 at NSPI and refunds to customers in 2017 for fuel clause over-recoveries collected in 2016 at Emera Florida and New Mexico. This was partially offset by an increase in accruals at TEC for restoration costs after Hurricane Irma.

Effect of Foreign Currency Translation

Emera operates globally, with an increasing amount of the Company’s adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and particularly the US dollar, which could positively or adversely affect results. Consistent with the Company’s risk management policies, currency risks are managed through matching US denominated debt to finance US operations and the use of short-term foreign currency derivative instruments to hedge specific transactions. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

Components of net income and adjusted net income are translated at the weighted average rate of exchange. The table below includes Emera's significant segments whose contribution to adjusted net income is recorded in US dollar currency.

millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Emera Florida and New Mexico	**$ 95**	$ 84	**$ 232**	$ 84
Emera Maine	**10**	13	**29**	27
Emera Caribbean	**9**	19	**23**	71
Emera Energy (1)	**3**	4	**7**	20
	117	120	**291**	202
Corporate and Other (2)	**(29)**	(29)	**(87)**	(30)
Total	**$ 88**	$ 91	**$ 204**	$ 172
FX rate for period	**$ 1.26**	$ 1.29	**$ 1.30**	$ 1.33

(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.

BUSINESS OVERVIEW AND OUTLOOK

Emera Florida and New Mexico

Emera Florida and New Mexico includes TECO Energy, the parent company of TEC, NMGC 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.

Emera Florida and New Mexico earnings are most directly impacted by the earned rate of return on equity ("ROE") and the capital structures approved by the FPSC and NMPRC, the prudent management and approved recovery of operating costs, the approved recovery of regulatory deferrals, sales volumes, and the timing and amount of capital expenditures.

The Florida utilities anticipate earning within their allowed ROE ranges in 2017 and expect rate base and earnings to be higher than prior years. Tampa Electric and PGS expect higher customer growth rates in 2017 than those experienced in 2016, reflective of economic growth in Florida. Assuming normal weather in the fourth quarter, annual sales are expected to be below 2016 due to warmer than normal weather in Q4 2016.

In accordance with the 2013 settlement agreement approved by the FPSC, Tampa Electric increased base rates by $110 million USD on January 16, 2017, the commercial operation date of the Polk Power Station expansion project. This expansion project added 460 MW of generating capacity and investment in related transmission system improvements needed to support the additional generation.

In September 2017, Tampa Electric was impacted by Hurricane Irma. The majority of Hurricane Irma restoration costs will be charged against Tampa Electric's FPSC approved storm reserve, resulting in minimal impact on Q3 2017 earnings. Estimated total restoration costs are $70 million USD with $60 million USD charged to the storm reserve, $6 million USD charged to capital expenditures and $4 million USD in Operating, maintenance and general ("OM&G") expense. Restoration costs charged to the storm reserve exceeded the balance by $14 million USD and this amount will be deferred and collected from customers in subsequent periods. Tampa Electric expects to petition the FPSC in early 2018 for recovery of the storm costs in excess of the reserve of $14 million USD and replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013.

Due to milder weather, NMGC expects 2017 earnings to be below prior years. Customer growth rates are expected to be consistent with 2016.

In 2017, Emera Florida and New Mexico expects to invest approximately $810 million USD, including allowance for funds used during construction ("AFUDC"), in capital projects compared to $795 million USD in 2016. Capital projects support normal system reliability and growth at the three utilities. In addition, 2017 capital projects at Tampa Electric include programs for transmission and distribution system storm hardening, distribution system modernization and automated metering equipment, transmission system reliability requirements and investments in utility scale solar photovoltaic projects.

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. A settlement agreement was filed with the FPSC requesting a base rate adjustment that provides for the recovery, upon in-service, of up to 600MW of investments in utility-scale solar projects that will be phased in from late 2018 through early 2021. On November 6, 2017, the FPSC approved the settlement agreement.

PGS will make investments to expand its system and support customer growth, and continue with replacement of obsolete plastic, cast iron and bare steel pipe. NMGC has undertaken a project relocating a portion of the gas pipeline feeding Taos, New Mexico, and will invest in their customer relationship management and billing system.

NSPI

NSPI is a fully-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, load demand, weather, the approved recovery of regulatory deferrals and the timing and amount of capital spending.

NSPI anticipates earning within its allowed ROE range in 2017 and expects its earnings and rate base to generally be consistent with prior years.

The future earnings impact of the carbon emission reduction strategy being developed from the Pan-Canadian Framework on Clean Growth and Climate Change is unknown. In October 2017, the Province of Nova Scotia passed amendments to the Environment Act to enable the development of a cap-and-trade program for carbon emissions. Under a cap-and-trade program, the provincial government will set a cap on the total amount of carbon emissions allowed in Nova Scotia and then issue individual emission allowances to regulated companies. If a company emits more than its allowance, it can buy allowances from other companies that have emitted less than their cap. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions will be recoverable from customers under NSPI's regulatory framework. NSPI continues to work with both the Province of Nova Scotia and the Government of Canada on details of the carbon emission reduction agreements and to advance solutions that are in the best interest of customers.

On September 11, 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link starting when the Maritime Link is in service. The forecasted in service date is January 2018. In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment payment reflects NSPML's proposal to reduce the assessment by deferring $53 million in each of 2018 and 2019, related to depreciation and amortization expenses. As these amounts are included in NSPI's 2017, 2018 and 2019 fuel rates and are being recovered from customers, NSPI will provide a one-time credit to customers, including interest, in 2018 of approximately $18 million, in 2019 of approximately $36 million and in 2020 of approximately $53 million of these recoveries from customers, as the payments from NSPI to NSPML are not required in those years.

NSPI is also required to hold back $10 million from the interim assessment payment to NSPML in each of 2018 and 2019. The release of such amounts is subject to providing evidence to the UARB that at least that amount of benefit from the Maritime Link has been realized for NSPI customers in that year. If the $10 million in benefits is realized, the UARB will direct NSPI to pay the $10 million to NSPML for that year. If not realized, then the UARB will direct NSPI to pay to NSPML only that portion that is realized and the balance will be refunded to customers through NSPI's Fuel Adjustment Mechanism ("FAM").

In 2017, NSPI expects to invest approximately $400 million, including AFUDC, in capital projects compared to $309 million in 2016. In addition to capital projects to support normal system reliability, 2017 includes spending on information technology and transmission projects.

Emera Maine

Emera Maine is a transmission and distribution 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, sales volumes, and the timing and amount of capital expenditures.

Emera Maine's 2017 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in growth in earnings.

There are currently four pending complaints filed with the FERC to challenge the ISO-New England ("ISO-NE") Open Access Transmission Tariff-allowed base ROE. On June 19, 2014, in connection with the first complaint, the FERC set the base ROE at 10.57 per cent and capped the total ROE, including the effect of incentive adders, at 11.74 per cent. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit vacated this order. No changes in reserves have been made as a result of the Court of Appeals vacating the FERC Order, as the outcome is considered uncertain. There are no further updates since December 31, 2016 for the other pending complaints. For further discussion on the complaints, see note 19 to the condensed consolidated interim financial statements for the quarter ended September 30, 2017.

In 2017, Emera Maine expects to invest approximately $75 million USD (2016 – $69 million USD actual) primarily on transmission and distribution capital projects.

Emera Caribbean

Emera Caribbean includes Emera (Caribbean) Incorporated ("ECI") and its wholly owned subsidiary BLPC, a vertically integrated utility that is the provider of electricity in Barbados; an 80.4 per cent interest in GBPC, a vertically integrated utility and the sole provider of electricity on Grand Bahama Island; and a 51.9 per cent interest in Domlec, an integrated utility on the island of Dominica. In addition, Emera Caribbean includes a 19.1 per cent equity interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia.

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, sales volumes and the timing and scale of capital expenditures.

Emera Caribbean's 2017 earnings are expected to be less than prior years, excluding the impact of the Q2 2016 gain recognized on the Self-Insurance Fund regulatory liability. This is the result of higher interest charges in ECI on new debt issued in Q4 2016 and expected short-term load decline in GBPC from Hurricane Matthew in 2016.

On May 30, 2017, the Minister of Finance in Barbados delivered a new budget. Key measures include an increase in the National Social Responsibility Levy (NSRL) from two per cent to 10 per cent and the introduction of a two per cent foreign exchange commission, both effective July 1, 2017. The NSRL is charged on all goods imported into Barbados and on domestically manufactured goods. The impact of these immaterial changes will be incorporated into BLPC's cost of service.

The 2017 Atlantic hurricane season has been active. The island of Grand Bahama was impacted by Hurricane Irma, however there was minimal damage to the system as a result of the storm. The island of Dominica took a direct hit from Maria, a Category 5 hurricane. Emera's total investment in Domlec is $7 million USD. Refer to the "Developments" section for further details about Domlec and the impact of Hurricane Maria. Barbados has not been affected by any hurricanes this season.

On November 8, 2017, the minority shareholders of ICD Utilities Limited approved Emera's acquisition of their common shares for total consideration of approximately $35 million USD. Completion of this transaction is anticipated in Q4 2017, at which time Emera's interest in GBPC will increase from 80.4 per cent to 100 per cent.

Emera Caribbean plans to invest approximately $75 million USD in capital programs in 2017 (2016 - $65 million USD actual). Capital projects in 2017 include investment in energy storage, advanced metering infrastructure ("AMI") and renewables.

Emera Energy

Emera Energy includes EES, a wholly owned physical energy marketing and trading business; 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.

Emera Energy Services

EES, Emera Energy's marketing and trading business, is 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, with the opportunity for upside when market conditions present. The weak market conditions experienced to date in 2017 may result in annual earnings falling short of the low end of the range.

Emera Energy Generation

Earnings from EEG's assets are largely dependent on market conditions, in particular, the relative pricing of electricity and natural gas; and capacity pricing for NEGG. Efficient operations of the fleet to ensure unit availability, cost management, and effective commercial management are key success factors.

Adjusted earnings from Emera Energy's generating assets in 2017 are expected to be in line with 2016. Higher capacity prices that came into effect in June 2017 and the negative impact on 2016 earnings from the recognition of prior year state fuel taxes are expected to be offset by lower realized spark spreads year-over-year and to a lesser extent, the impact of an unplanned outage at the Bridgeport facility. The unit was taken offline for repair in mid-March 2017 and was returned to service in mid-June 2017.

In 2017, Emera Energy expects to invest approximately $50 million (2016 – $39 million) in capital related to its generating assets in order to further improve reliability and enhance plant output capacity.

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 (100 per cent investment), LIL (53.7 per cent investment) and M&NP (12.9 per cent investment). 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 adjusted net income is expected to be lower in 2017, primarily due to the 2016 gains associated with the sale of Emera's investment in APUC and higher interest costs in 2017 as a result of permanent financing in place for the TECO Energy acquisition. This will be partially offset by higher OM&G expenses in 2016 related to the TECO Energy acquisition and higher earnings in 2017 from Emera's investment in ENL's projects (NSPML and LIL).

Corporate and Other, excluding ENL, expects to spend approximately $23 million on property, plant and equipment in 2017 (2016 - $7 million).

ENL

Throughout construction of both the Maritime Link Project and LIL, equity earnings in ENL are a result of AFUDC. Therefore, 2017 equity earnings contribution from ENL will be higher than 2016 as a result of Emera's additional equity contribution while under construction, resulting in higher equity levels, and therefore higher AFUDC earnings.

NSPML

Future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for construction activities and the approved ROE, which will determine the component of costs to be funded by equity. The Maritime Link Project is accounted for in Emera's financial statements as an equity investment (see note 5 of the Condensed Consolidated Interim Financial Statements). The Company's earnings through the construction period are derived from AFUDC on Emera's equity investment of 30 per cent of the project costs to maintain a 70 per cent to 30 per cent debt-to-equity ratio. As Maritime Link construction costs are incurred, Emera will contribute equity and then earn AFUDC on that contribution. Maritime Link forecasted cash equity contributions for 2017 are $175 million, with total equity contributions for the Project estimated to be $450 million.

LIL

Future earnings from the LIL investment are dependent on the amount and timing of additional equity investments and the approved ROE. Emera's total 2017 cash equity contributions are $55 million, with the Company's total equity contribution for the project estimated to be approximately $600 million.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the condensed consolidated balance sheets between December 31, 2016 and September 30, 2017 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ (183)**	Decreased primarily due to additions of property, plant and equipment, increased investment in LIL and NSPML and payment of common dividends. These decreases were partially offset by changes in credit facilities, proceeds of long-term debt at GBPC, and changes in short-term debt at Emera Florida and New Mexico.
Receivables, net	**(118)**	Decreased mainly due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries, timing of collection at TEC as a result of Hurricane Irma, and seasonal trends of the business at Emera Florida and New Mexico, NSPI and Emera Energy.
Property, plant and equipment, net of accumulated depreciation	**(598)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and depreciation, partially offset by additions primarily at NSPI and Emera Florida and New Mexico.
Investments subject to significant influence	**220**	Increased mainly due to investment in NSPML and LIL.
Goodwill	**(438)**	Decreased due to the effect of a stronger CAD on the translation of Emera’s foreign subsidiaries.
Prepayments and other assets (current and long-term)	**(141)**	Decreased due to amortization of transportation assets, partially offset by new Asset Management Agreements (“AMA”) at Emera Energy.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(605)**	Decreased due to the effect of a stronger CAD on foreign currency long-term debt. This was partially offset by changes in credit facilities, proceeds of long-term debt at GBPC, and changes in short-term debt at Emera Florida and New Mexico.
Accounts payable	**(172)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries, seasonal trends of the business at Emera Energy, and timing of expenditure payments. These were partially offset with increased accruals at TEC for restoration costs after Hurricane Irma, and increased cash collateral position on derivative instruments at NSPI.
Deferred income tax liabilities, net of deferred income tax assets	**118**	Increased due to tax deductions in excess of accounting deductions related to property, plant and equipment, and the decrease in accumulated reserve – cost of removal, pension and post-retirement and other liabilities. This was partially offset by increased tax loss carry forwards, and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Derivative instruments (current and long-term)	**(247)**	Decreased due to the reversal of 2016 Emera Energy AMA MTM losses, and changes in existing positions on long term natural gas contracts.
Regulatory liabilities (current and long-term)	**(307)**	Decrease reflects lower deferred fuel clause, accumulated cost of removal and transmission and delivery storm reserve for TEC, and decreased regulated derivatives at NSPI, partially offset by an increased FAM regulatory liability at NSPI.
Pension and post-retirement liabilities (current and long-term)	**(113)**	Decreased due to supplemental executive retirement plan and other post-retirement payments in Emera Florida and New Mexico, and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Other liabilities (current and long-term)	**189**	Increase is driven by the timing of Emera’s dividend payments and timing of interest payments on long-term debt in TEC, and Emera.

Common stock	**137**	Increased due to issuance of common stock for the dividend reinvestment program.
Accumulated other comprehensive income	**(344)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.

DEVELOPMENTS

Increase in Common Dividend

On September 29, 2017, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.09 to $2.26. The first payment at the increased rate will be effective November 15, 2017.

Hurricanes Irma and Maria

During the third quarter of 2017, operations in Florida and the Caribbean were impacted by Hurricanes Irma and Maria. Irma, a Category 5 hurricane at its height, impacted the Caribbean and Florida over the course of several days in September making landfall in Florida on September 10, 2017. Hurricane Maria made landfall in Dominica on September 19, 2017, as a Category 5 hurricane. There were no material impacts from these storms on St. Lucia, Grand Bahamas or Barbados.

TEC – As a result of Hurricane Irma, 57 per cent of Tampa Electric customers lost power. Power was restored to substantially all customers within seven days. There was minimal impact to Q3 earnings as a result of this storm. TEC incurred $70 million USD of storm restoration costs in the third quarter of 2017, of which $60 million USD are expected to be recoverable from the transmission and delivery storm reserve, $6 million USD were charged to capital expenditures and $4 million USD to OM&G expenses. Refer to the "Business Overview and Outlook", "Emera Florida and New Mexico" section for further details.

Domlec – Emera owns a controlling 51.9 per cent interest in Domlec, an integrated utility on the island of Dominica. The 48.1 per cent non-controlling interest is held by Dominica Social Security, the national pension scheme controlled by the Government, and other investors. Emera's total investment in Domlec is $7 million USD. On September 19, 2017, Dominica experienced unprecedented damage as a result of Hurricane Maria, facing winds of 175 miles per hour. All 36,000 of Domlec's customers lost power following the storm. Domlec has begun restoring power to specific vital services and will continue to work with the Government of Dominica to identify the next priorities for restoration.

While Domlec's generating assets survived the storm with minimal damage, the Company's transmission and distribution assets were significantly impacted. Domlec maintains insurance for its generation fleet and, as with most utilities, transmission and distribution networks are self-insured. The country's overall restoration plan for the island's infrastructure is not yet completed, and as a result, the Company is unable to estimate the possible financial loss, range of financial loss or recovery related to this storm. It is expected that sufficient information will be available by end of year.

As a result of Emera owning a controlling interest of 51.9 per cent of Domlec, the Company consolidates 100 per cent of Domlec assets, liabilities, revenue and expenses in its books with an offset for the portion that is not owned by Emera as "Non-controlling interest in Subsidiaries" in the income statements and "Non-controlling interest" in the equity section of the balance sheet. As of September 30, 2017, the Company's balance sheet includes total assets of $62 million USD related to Domlec. Significant assets include $16 million USD net book value which relates to generation assets, $26 million USD net book value of transmission and distribution assets, $5 million USD of accounts receivable, $4 million USD of inventory and $11 million USD of other assets. All of Domlec's $8 million USD of long term debt is held by the National Bank of Dominica Ltd. The National Bank has indicated they will defer payment of principal on Domlec's loan as a result of the hurricane. Emera's total investment in Domlec is $7 million USD.

NSPML cost recovery

On September 11, 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link commencing when it is in service. The approved annual interim assessment payments are $110 million in 2018 and $111 million in 2019. In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment reflects NSPML's proposal to reduce the assessment by deferring the portion related to depreciation and amortization expense until such time as energy is being delivered. Refer to the "Business Overview and Outlook", "NSPI" section for further details.

TEC Solar Investment and Solar Base Rate Adjustment ("SoBRA")

On September 28, 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new solar projects across its service territory. The first phase, which includes two projects totaling 150 MW, is scheduled to be completed in September 2018. The second phase, which includes four projects totaling 250 MW, is scheduled to be completed by January 1, 2019. Two other phases are scheduled to be completed by January 1 of 2020 and 2021.

A settlement agreement was filed with the FPSC requesting a base rate adjustment that provides for the recovery, upon in service, of up to 600MW of investments in utility-scale solar projects. The settlement agreement also extends the general base rate freeze included in the 2013 Agreement to January 1, 2022, limits fuel hedging and investments in natural gas reserves and includes certain customer protections related to potential changes in federal tax policy. On November 6, 2017, the FPSC approved the settlement agreement.

Appointments

Board of Directors
Effective November 10, 2017, Kent M. Harvey joined the Emera Board of Directors. Mr. Harvey is the former Chief Financial Officer for PG&E Corporation, a Fortune 200 regulated electric and gas utility.

Executive
Effective December 1, 2017, Nancy Tower will be appointed President and Chief Executive Officer of Tampa Electric. Gordon Gillette, Tampa Electric's current President and Chief Executive Officer, will retire on November 30, 2017. Ms. Tower is currently the Chief Corporate Development Officer for Emera.

On March 29, 2017, Chris Huskilson provided notice of his intention to retire as Chief Executive Officer ("CEO") in 2018. Concurrently, Emera's Board of Directors announced it will appoint Scott Balfour, current Chief Operating Officer and former Chief Financial Officer, as CEO upon Mr. Huskilson's retirement.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars	
Balance, December 31, 2015	147.21	$	2,157
Conversion of Convertible Debentures	51.99		2,115
Issuance of common stock	7.69		338
Issued for cash under Purchase Plans at market rate	2.51		115
Discount on shares purchased under Dividend Reinvestment Plan	-		(5)
Options exercised under senior management stock option plan	0.62		17
Employee Share Purchase Plan	-		1
Balance, December 31, 2016	210.02	$	4,738
Conversion of Convertible Debentures (1)	0.14		6
Issued for cash under Purchase Plans at market rate	2.91		135
Discount on shares purchased under Dividend Reinvestment Plan	-		(7)
Options exercised under senior management stock option plan	0.07		2
Employee Share Purchase Plan	-		1
Balance, September 30, 2017	**213.14**	**$**	**4,875**

(1) As at September 30, 2017, a total of 52.13 million common shares of the Company were issued, representing conversion into common shares of more than 99.9% of the Convertible Debentures.

As at October 27, 2017 the amount of issued and outstanding common shares was 213.2 million.

The weighted average shares of common stock outstanding – basic for the three months ended September 30, 2017 was 213.8 million (2016 – 182.8 million) and for the nine months ended September 30, 2017 was 212.7 million (2016 – 160.5 million). The weighted average shares of common stock outstanding – basic, includes both issued and outstanding common stock, as shown above, and outstanding deferred share units.

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			
		2017		2016		**2017**		**2016***
Operating revenues – regulated electric	**$**	**596**	$	585	**$**	**1,578**	$	**585**
Operating revenues – regulated gas		**139**		147		**526**		**147**
Operating revenues – non-regulated		**3**		3		**9**		**3**
Total operating revenues		**738**		735		**2,113**		**735**
Regulated fuel for generation and purchased power		**181**		212		**491**		**212**
Regulated cost of natural gas		**57**		53		**208**		**53**
Contribution to consolidated net income – USD	**$**	**95**	$	84	**$**	**232**	$	**84**
Contribution to consolidated net income – CAD	**$**	**120**	**$**	109	**$**	**302**	**$**	**109**
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.56**	$	0.60	**$**	**1.42**	$	**0.68**
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.26**	$	1.30	**$**	**1.30**	$	**1.30**
EBITDA – USD	**$**	**298**	$	268	**$**	**808**	$	**268**
EBITDA – CAD	**$**	**374**	$	350	**$**	**1,054**	$	**350**

*Financial results of Emera Florida and New Mexico are from July 1, 2016.

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
Contribution to consolidated net income – 2016	**$**	**84**
Increased operating revenues - see Operating Revenues - Regulated Electric below		11
Decreased operating revenues - see Operating Revenues - Regulated Gas below		(8)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		31
Increased cost of natural gas sold - see Regulated Cost of Natural Gas below		(4)
Decreased OM&G expenses primarily due to lower labour related expenses, higher administrative overhead allocated to capital due to higher capital spending and lower pension expense; partially offset by incremental spending related to Hurricane Irma		5
Increased depreciation and amortization due to increased property, plant and equipment; partially offset by decreases in depreciation rates related to PGS's FPSC approved depreciation study		(4)
Decreased AFUDC due to Polk Power Station expansion going into service in January 2017		(9)
Increased income tax expense primarily due to increased income before provision for income taxes		(10)
Other		(1)
Contribution to consolidated net income – 2017	**$**	**95**

Emera Florida and New Mexico's CAD contribution to consolidated net income increased $11 million to $120 million in Q3 2017 from $109 million during the same period in 2016. The impact of the change in the foreign exchange rate decreased CAD earnings by $5 million compared to Q3 2016.

Emera Florida and New Mexico's contribution is summarized in the following table:

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016*
Tampa Electric	**$ 98**	$ 88	**$ 217**	$ 88
PGS	**7**	6	**31**	6
NMGC	**(1)**	(1)	**12**	(1)
Other (1)	**(9)**	(9)	**(28)**	(9)
Contribution to consolidated net income	**$ 95**	$ 84	**$ 232**	$ 84

(1) Other includes TECO Finance and administration costs.
*Financial results of Emera Florida and New Mexico are from July 1, 2016.

Emera year-to-date results in 2016 reflect three months of Emera Florida and New Mexico operations as the acquisition was completed on July 1, 2016. Prior year-to-date data discussed below reflects the full nine months of operation for comparison purposes only.

Year-to-date, Tampa Electric's net income increased $10 million to $217 million compared to $207 million for the same period in 2016 due primarily to higher base revenues related to the completion of the Polk Power Station expansion project partially offset by increased depreciation and property tax expense, and lower AFUDC earnings. Unfavourable winter weather impacts on base revenues were offset by warmer spring weather experienced earlier this year and customer growth.

In September 2017, Tampa Electric was impacted by Hurricane Irma. The majority of Hurricane Irma restoration costs will be charged against Tampa Electric's FPSC approved storm reserve resulting in minimal impact on earnings. Estimated total restoration costs are $70 million, with $60 million charged to the storm reserve, $6 million charged to capital expenditures and $4 million charged to OM&G.

On June 29, 2017, a tragic accident occurred during work being conducted at Tampa Electric's Big Bend Power Station Unit Two, resulting in employee and contractor fatalities. Although the financial impact to Tampa Electric has not been fully determined, any such impact is expected to be substantially covered by insurance.

Year-to-date, PGS's net income increased $5 million to $31 million compared to $26 million for the same period in 2016 primarily due to lower depreciation expense and an increase in return on investments related to the FPSC approved Cast Iron/Bare Steel Pipe Replacement clause. Base rate revenue is flat as impacts from customer growth and the strong Florida economy have been offset by unfavourable winter weather impacts earlier this year.

Year-to-date, NMGC's net income decreased $2 million to $12 million compared to $14 million for the same period in 2016.

Year-to-date, other net loss increased $3 million to $28 million compared to $25 million for the same period in 2016.

Operating Revenues – Regulated Electric

Electric revenues increased $11 million to $596 million in Q3 2017 compared to $585 million in Q3 2016 primarily due to $34 million of higher base rate revenue related to completion of the Polk Power Station expansion in January 2017. This increase was offset by lower sales volumes and lower clause-related revenues due to return of prior year fuel over-recoveries through current rates. Year-to-date, electric revenues increased $71 million to $1,578 million in 2017 compared to $1,507 million in 2016 primarily due to $84 million of higher base rate revenue related to the Polk Power Station expansion offset by lower sales volumes and lower clause-related revenues.

Electric revenues are summarized in the following by customer class:

Q3 Electric Revenues	Three months ended	
millions of US dollars	September 30	
	2017	2016
Residential	**$ 316**	$ 331
Commercial	**159**	167
Industrial	**40**	42
Other (1)	**81**	45
Total	**$ 596**	$ 585

(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

YTD Electric Revenues	Nine months ended	
millions of US dollars	September 30	
	2017	2016*
Residential	**$ 769**	$ 331
Commercial	**439**	167
Industrial	**119**	42
Other (1)	**251**	45
	$ 1,578	$ 585

(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

*Financial results of Emera Florida and New Mexico are from July 1, 2016.

Q3 Electric Sales Volumes		
Gigawatt hours ("GWh")		
	2017	2016
Residential	**2,861**	2,960
Commercial	**1,792**	1,814
Industrial	**522**	499
Other	**480**	503
Total	**5,655**	5,776

YTD Electric Sales Volumes		
GWh		
	2017	2016*
Residential	**6,916**	7,116
Commercial	**4,859**	4,767
Industrial	**1,530**	1,438
Other	**1,282**	1,351
Total	**14,587**	14,672

*2016 YTD data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Operating Revenues – Regulated Gas

Gas revenues decreased $8 million to $139 million in Q3 2017 compared to $147 million in Q3 2016 primarily due to a decrease in revenues related to off system sales partially offset by an increase in the pass through of higher commodity costs and customer growth in Florida. Year-to-date, gas revenues increased $3 million to $526 million in 2017 compared to $523 million in 2016 primarily due to higher commodity costs and customer growth in Florida, partially offset by unfavourable winter weather in Q1 2017 in both Florida and New Mexico.

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

Q3 Gas Revenues

millions of US dollars	Three months ended September 30 **2017**	2016
Residential	**$ 57**	$ 56
Commercial	**45**	42
Industrial	**9**	9
Other (1)	**28**	40
Total	**$ 139**	$ 147

(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

YTD Gas Revenues

millions of US dollars	Nine months ended September 30 **2017**	2016*
Residential	**$ 257**	$ 56
Commercial	**160**	42
Industrial	**26**	9
Other (1)	**83**	40
Total	**$ 526**	$ 147

(1) Other includes regulatory deferrals related to over-recovery of clause related costs.
*TECO Energy was acquired on July 1, 2016.

Q3 Gas Sales Volumes

Therms (millions)	**2017**	2016
Residential	**34**	35
Commercial	**153**	150
Industrial	**318**	328
Other	**93**	91
Total	**598**	604

YTD Gas Sales Volumes

Therms (millions)	**2017**	2016*
Residential	**231**	249
Commercial	**552**	562
Industrial	**924**	947
Other	**192**	243
Total	**1,899**	2,001

*2016 YTD data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Regulated Fuel for Generation, Purchased Power and Cost of Natural Gas

Electric Capacity

Regulated fuel for generation and purchased power decreased $31 million to $181 million in Q3 2017 compared to $212 million in Q3 2016 and year-to-date decreased $16 million to $491 million in 2017 compared to $507 million in 2016 due to lower sales volumes and a change in generation mix to lower cost natural gas from purchased power.

Q3 Production Volumes

GWh	**2017**	2016
Natural gas (1)	**4,498**	2,493
Coal (2)	**966**	2,409
Oil and petcoke	**160**	296
Solar	**12**	1
Purchased power, net (1)	**347**	846
Total production volumes	**5,983**	6,045

(1) Natural gas production was higher and purchased power was lower due to completion of Polk Power Station expansion in January 2017 and expiration of a purchased power contract in December 2016.
(2) Lower coal production due to outages at Big Bend Power Station.

YTD Production Volumes

GWh	**2017**	2016*
Natural gas (1)	**10,262**	7,912
Coal	**4,244**	4,895
Oil and petcoke	**696**	752
Solar	**35**	2
Purchased power (1)	**388**	2,065
Total production volumes	**15,625**	15,626

(1) Natural gas production was higher and purchased power was lower due to completion of Polk Power Station expansion in January 2017 and expiration of a purchased power contract in December 2016.
*2016 YTD data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

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

		2017		2016
Dollars per MWh	**$**	**30**	$	**35**

YTD Average Fuel Costs/MWh
US dollars

		2017		2016*
Dollars per MWh	**$**	**31**	$	**32**

*2016 YTD data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Average fuel cost per MWh decreased in Q3 2017 and year-to-date primarily due to lower purchased power and more natural gas production as a result of new Polk Power Station expansion.

Cost of Natural Gas

Regulated cost of natural gas increased $4 million to $57 million in Q3 2017 compared to $53 million in Q3 2016 primarily due to higher commodity costs. Year-to-date, regulated cost of natural gas increased $7 million to $208 million in 2017 compared to $201 million in 2016 primarily due to higher commodity costs partially offset by lower sales volumes due to unfavourable winter weather in Q1 2017.

Gas sales by type are summarized in the following table:

Q3 Gas Sales Volumes by Type
Therms (millions)

	2017	2016
System Supply	**138**	131
Transportation	**460**	473
Total	**598**	604

YTD Gas Sales Volumes by Type
Therms (millions)

	2017	2016*
System Supply	**477**	546
Transportation	**1,422**	1,455
Total	**1,899**	2,001

*2016 YTD data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

NSPI

Financial Highlights

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30				Nine months ended September 30		
		2017		2016		**2017**		2016
Operating revenues – regulated electric	**$**	**283**	$	292	**$**	**983**	$	1,004
Regulated fuel for generation and purchased power		**99**		112		**336**		354
Contribution to consolidated net income	**$**	**7**	$	15	**$**	**106**	$	96
Contribution to consolidated earnings per common share – basic	**$**	**0.03**	$	0.08	**$**	**0.50**	$	0.60
EBITDA	**$**	**93**	$	96	**$**	**362**	$	347

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 – 2016	**$ 15**	**$ 96**
Decreased operating revenues - see Operating Revenues - Regulated Electric below	(9)	(21)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	13	18
Increased FAM and fixed costs deferrals quarter-over-quarter due to increased recovery of current year fuel costs including the impact of the Maritime Link interim assessment decision. Year-over-year decreased due to the rebate to customers of prior years' over-recovery of fuel costs and the impact of the Maritime Link interim decision partially offset by increased recovery of current year fuel costs	(7)	5
Decreased OM&G expenses year-over-year primarily due to higher administrative overhead allocated to capital due to higher capital spending, decreased storm costs, lower pension expense and lower maintenance costs	-	13
Decreased income tax expense year-over-year primarily due to increased tax deductions in excess of accounting depreciation related to property, plant and equipment	(1)	6
Other	(4)	(11)
Contribution to consolidated net income – 2017	**$ 7**	**$ 106**

Operating Revenues – Regulated Electric

Operating revenues decreased $9 million to $283 million in Q3 2017 compared to $292 million in Q3 2016 resulting from $12 million related to the Maritime Link interim assessment decision which was partially offset by a $5 million increase in fuel related electricity pricing.

Year-to-date, operating revenues decreased $21 million to $983 million in 2017 compared to $ 1,004 million in 2016. Revenues were decreased due to the one-time refund in 2017 of $36 million of prior year fuel related revenues and by $12 million due to the Maritime Link interim assessment decision. This was partially offset by an $18 million increase as a result of fuel related electricity pricing effective January 1, 2017 and a $7 million increase in residential sales volume due to load growth.

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

Q3 Electric Revenues
millions of Canadian dollars

	2017	2016
Residential	**$ 126**	$ 129
Commercial	**91**	94
Industrial	**50**	50
Other	**9**	11
Total	**$ 276**	$ 284

YTD Electric Revenues
millions of Canadian dollars

	2017	2016
Residential	**$ 501**	$ 508
Commercial	**286**	298
Industrial	**144**	146
Other	**30**	32
Total	**$ 961**	$ 984

Q3 Electric Sales Volumes
GWh

	2017	2016
Residential	**784**	777
Commercial	**722**	729
Industrial	**615**	645
Other	**74**	69
Total	**2,195**	2,220

YTD Electric Sales Volumes
GWh

	2017	2016
Residential	**3,254**	3,175
Commercial	**2,289**	2,298
Industrial	**1,829**	1,813
Other	**260**	213
Total	**7,632**	7,499

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $13 million to $99 million in Q3 2017 compared to $112 million in Q3 2016 due to decreased commodity prices. Year-to-date, regulated fuel for generation and purchased power decreased $18 million to $336 million in 2017 compared to $354 million during the same period in 2016 due to decreased solid fuel pricing, partially offset by increased sales volumes.

NSPI's FAM regulatory liability balance increased $61 million from $94 million at December 31, 2016 to $155 million at September 30, 2017 as a result of an over-recovery of current period fuel costs, the impact of the Maritime Link interim assessment decision, the application of non-fuel revenues and interest on the FAM balance reduced by the refund to customers of prior years' fuel costs.

Q3 Production Volumes
GWh

	2017	2016
Coal	**986**	1,121
Natural gas	**477**	378
Oil and petcoke	**241**	253
Purchased power – other	**125**	112
Total non-renewables	**1,829**	1,864
Wind and hydro – renewables	**168**	133
Purchased power – Independent Power Producers ("IPP")	**220**	219
Purchased power – Community Feed-in Tariff program ("COMFIT")	**95**	94
Biomass – renewables	**20**	56
Total renewables	**503**	502
Total production volumes	**2,332**	2,366

YTD Production Volumes
GWh

	2017	2016
Coal	**3,671**	3,430
Natural gas	**1,095**	963
Oil and petcoke	**817**	1,108
Purchased power – other	**261**	301
Total non-renewables	**5,844**	5,802
Wind and hydro – renewables	**931**	851
Purchased power – IPP	**872**	833
Purchased power – COMFIT	**367**	304
Biomass – renewables	**100**	162
Total renewables	**2,270**	2,150
Total production volumes	**8,114**	7,952

Q3 Average Fuel Costs

	2017	2016
Dollars per MWh produced	**$ 42**	$ 47

YTD Average Fuel Costs

	2017	2016
Dollars per MWh produced	**$ 41**	$ 45

Average fuel costs decreased in Q3 2017 and year-to-date primarily due to favourable solid fuel pricing and increased hydro and wind production.

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	
	2017	2016	**2017**	2016
Operating revenues – regulated electric	**$ 59**	$ 59	**$ 173**	$ 168
Regulated fuel for generation and purchased power (1)	**18**	15	**47**	42
Contribution to consolidated net income – USD	**$ 10**	$ 13	**$ 29**	$ 27
Contribution to consolidated net income – CAD	**$ 13**	$ 17	**$ 38**	$ 36
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.06**	$ 0.09	**$ 0.18**	$ 0.22
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.26**	$ 1.30	**$ 1.30**	$ 1.32
EBITDA – USD	**$ 27**	$ 31	**$ 84**	$ 79
EBITDA – CAD	**$ 34**	$ 39	**$ 110**	$ 104

(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 – 2016	**$ 13**	**$ 27**
Increased operating revenues - regulated electric (see Operating Revenues - Regulated Electric Section below)	-	5
Increased regulated fuel for generation and purchased power due to changes in long-term purchased power contracts and transmission pool expenses	(3)	(5)
Increased OM&G due to lower capitalized construction overheads as a result of lower capital spending in the quarter. Decreased OM&G year-to-date due to storm expenses incurred in 2016 and increased capitalized construction overheads in 2017	(2)	4
Increased income tax expense year-over-year primarily due to increased income before provision for income taxes	1	(3)
Other	1	1
Contribution to consolidated net income – 2017	**$ 10**	**$ 29**

Emera Maine's CAD contribution to consolidated net income decreased $4 million to $13 million in Q3 2017 from $17 million in Q3 2016 and year-over-year increased $2 million to $38 million in 2017 from $36 million during the same period in 2016. The foreign exchange rate had minimal impact for the three months and nine months ended September 30, 2017.

Operating Revenues – Regulated Electric

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

		2017		2016
Electric revenues	$	**45**	$	41
Transmission pool revenues		**13**		16
Resale of purchased power		**1**		2
Operating revenues – regulated electric	$	**59**	$	59

YTD Operating Revenues – Regulated Electric
millions of US dollars

		2017		2016
Electric revenues	$	**128**	$	120
Transmission pool revenues		**38**		39
Resale of purchased power		**7**		9
Operating revenues – regulated electric	$	**173**	$	168

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

Q3 Electric Revenues
millions of US dollars

		2017		2016
Residential	$	**19**	$	19
Commercial		**15**		16
Industrial		**4**		4
Other (1)		**7**		2
Total	$	**45**	$	41

YTD Electric Revenues
millions of US dollars

		2017		2016
Residential	$	**60**	$	57
Commercial		**46**		45
Industrial		**10**		10
Other (1)		**12**		8
Total	$	**128**	$	120

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

Electric revenues increased $4 million to $45 million in Q3 2017 compared to $41 million in Q3 2016. Year-to-date, electric revenues increased $8 million to $128 million in 2017 compared to $120 million during the same period in 2016 due to transmission and distribution rate changes.

Electric sales volume are summarized in the following tables by customer class:

Q3 Electric Sales Volumes
GWh

	2017	2016
Residential	**188**	194
Commercial	**198**	203
Industrial	**97**	101
Other	**4**	3
Total	**487**	501

YTD Electric Sales Volumes
GWh

	2017	2016
Residential	**595**	588
Commercial	**579**	584
Industrial	**262**	267
Other	**11**	11
Total	**1,447**	1,450

Regulated Fuel for Generation and Purchased Power

Emera Maine’s regulated fuel for generation and purchased power increased $3 million to $18 million in Q3 2017 compared to $15 million in Q3 2016. Year-to-date, regulated fuel for generation and purchased power increased $5 million to $47 million in 2017 compared to $42 million during the same period in 2016. The increases were due to increased volumes and changes in market prices associated with long term purchase power contracts.

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
		2017		2016		**2017**		2016
Operating revenues – regulated electric	**$**	**87**	$	89	**$**	**250**	$	238
Regulated fuel for generation and purchased power		**39**		37		**111**		94
Contribution to consolidated net income – USD	**$**	**9**	$	19	**$**	**23**	$	71
Contribution to consolidated net income – CAD	**$**	**12**	$	24	**$**	**30**	$	92
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.06**	$	0.13	**$**	**0.14**	$	0.57
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.25**	$	1.31	**$**	**1.30**	$	1.30
EBITDA – USD	**$**	**28**	$	36	**$**	**76**	$	125
EBITDA – CAD	**$**	**35**	$	46	**$**	**99**	$	164

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 – 2016	**$**	**19**	$	**71**
(Decreased) increased operating revenues - see Operating Revenues - Regulated Electric below		(2)		12
Increased regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below		(2)		(17)
Decreased other income quarter-over-quarter mainly due to the recognition of gains in the prior year on the sale of investment securities. Year-over-year decrease mainly due to a pre-tax gain recognized on the BLPC SIF regulatory liability in 2016		(3)		(44)
Decreased income tax expense year-over-year mainly due to a pre-tax gain recognized on the BLPC SIF regulatory liability in 2016		-		7
Increased interest expense reflecting interest charges on new debt issued in Q4 2016 at ECI		(2)		(6)
Other		(1)		-
Contribution to consolidated net income – 2017	**$**	**9**	$	**23**

Emera Caribbean's CAD contribution to consolidated net income decreased by $12 million to $12 million in Q3 2017 compared to $24 million in Q3 2016 and year-over-year decreased by $62 million to $30 million in 2017 compared to $92 million during the same period in 2016. The foreign exchange rate had minimal impact for the three and nine months ended September 30, 2017.

Operating Revenues – Regulated Electric

Operating revenues decreased $2 million to $87 million in Q3 2017 compared to $89 million in Q3 2016. This decrease reflected lower sales volumes at Domlec due to damage during Hurricane Maria and at GBPC due to the continued effect of Hurricane Matthew, partially offset by an increase in fuel charge as a result of higher fuel prices in 2017 at BLPC.

Year-to-date, operating revenues increased $12 million to $250 million in 2017 compared to $238 million during the same period in 2016 due to an increase in fuel charge as a result of higher fuel prices in 2017 at BLPC, partially offset by lower sales volumes at GBPC due to the continued effect of Hurricane Matthew and at Domlec due to the impact of Hurricane Maria.

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

Q3 Electric Revenues
millions of US dollars

	2017	2016
Residential	**$ 30**	$ 30
Commercial	**49**	49
Industrial	**6**	7
Other	**2**	2
Total	**$ 87**	$ 88

YTD Electric Revenues
millions of US dollars

	2017	2016
Residential	**$ 83**	$ 78
Commercial	**142**	133
Industrial	**17**	19
Other	**5**	5
Total	**$ 247**	$ 235

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

Q3 Electric Sales Volumes
GWh

	2017	2016
Residential	**127**	129
Commercial	**197**	207
Industrial	**22**	25
Other	**5**	5
Total	**351**	366

YTD Electric Sales Volumes
GWh

	2017	2016
Residential	**353**	355
Commercial	**569**	581
Industrial	**65**	72
Other	**13**	16
Total	**1,000**	1,024

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $2 million to $39 million in Q3 2017 compared to $37 million in Q3 2016 and year-to-date increased $17 million to $111 million in 2017 compared to $94 million during the same period in 2016 primarily due to higher oil prices.

Q3 Production Volumes
GWh

	2017	2016
Oil	**369**	383
Hydro	**6**	9
Solar	**3**	5
Total	**378**	397

YTD Production Volumes
GWh

	2017	2016
Oil	**1,047**	1,080
Hydro	**25**	27
Solar	**13**	5
Total	**1,085**	1,112

Q3 Average Fuel Costs/MWh
US dollars

	2017	2016
Dollars per MWh	**$ 103**	$ 93

YTD Average Fuel Costs/MWh
US dollars

	2017	2016
Dollars per MWh	**$ 102**	$ 85

The change in the average fuel costs for the quarter and year-to-date was the result of 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	
	2017	2016	**2017**	2016
Marketing and trading margin (1)	**$ (4)**	$ 2	**$ 20**	$ 35
Electricity sales (2)	**75**	94	**230**	351
Total operating revenues – non-regulated	**71**	96	**250**	386
Non-regulated fuel for generation and purchased power (3)	**42**	61	**149**	250
Adjusted contribution to consolidated net income (loss)	**$ (1)**	$ -	**$ (2)**	$ 19
After-tax derivative mark-to-market gain (loss)	**$ (38)**	$ (109)	**$ 105**	$ (98)
Contribution to consolidated net income (loss)	**$ (39)**	$ (109)	**$ 103**	$ (79)
Adjusted contribution to consolidated earnings per common share – basic	**$ -**	$ -	**$ -**	$ 0.12
Contribution to consolidated earnings per common share – basic	**$ (0.18)**	$ (0.60)	**$ 0.48**	$ (0.50)
Adjusted EBITDA	**$ 14**	$ 15	**$ 46**	$ 74

(1) Marketing and trading margin excludes a pre-tax mark-to-market loss of $56 million in Q3 2017 (2016 - $150 million loss) and a gain of $156 million year-to-date in 2017 (2016 - $139 million loss).
(2) Electricity sales excludes a pre-tax mark-to-market of nil in Q3 2017 (2016 - $4 million loss) and a loss of $3 million year-to-date in 2017 (2016 - $7 million loss).
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market of nil in Q3 2017 (2016 - $3 million loss) and a loss of $4 million year-to-date in 2017 (2016 - $5 million gain).

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income (loss) – 2016	**$ (109)**	**$ (79)**
Decreased marketing and trading margin quarter-over-quarter and year-over-year – See Marketing and Trading Margin below	(6)	(15)
Decreased electricity sales quarter-over-quarter mainly due to decreased sales volumes at Bayside Power and NEGG driven by less favourable market conditions and lower power prices in Q3 2017 compared to Q3 2016; partially offset by higher capacity revenue for NEGG. Year-over-year also due to lower hedged power prices in Q1 2017 compared to Q1 2016, an unplanned outage at the Bridgeport Facility in 2017 and a planned outage at Bayside Power in Q2 2017	(19)	(121)
Decreased non-regulated fuel for generation and purchased power quarter-over-quarter mainly due to decreased sales volumes at Bayside Power and NEGG driven by less favourable market conditions. Year-over-year also due to the recognition of prior period state fuel taxes in Q2 2016, lower hedged natural gas prices in Q1 2017 compared to Q1 2016, an unplanned outage at the Bridgeport Facility in 2017 and a planned outage at Bayside Power in Q2 2017	19	101
Decreased income tax expense year-over-year primarily due to decreased income before provision for income taxes	-	11
Increased mark-to-market, net of tax quarter-over-quarter mainly due to changes in existing positions on long-term natural gas contracts. Year-over-year also due to the reversal of 2016 mark-to-market losses	71	203
Other	5	3
Contribution to consolidated net income (loss) – 2017	**$ (39)**	**$ 103**

A portion of earnings are exposed to foreign exchange fluctuations, thereby affecting adjusted CAD contribution to net earnings. The impact of the change in USD/CAD exchange rate quarter-over-quarter decreased the loss in CAD by $2 million in Q3 2017 compared to Q3 2016. Year-to-date the impact of the change in USD/CAD exchange rate decreased earnings in CAD by $11 million compared to the same period in 2016.

Emera Energy Services

Adjusted EBITDA

Adjusted EBITDA for Emera Energy Services is summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Marketing and trading margin	**$ (4)**	$ 2	**$ 20**	$ 35
OM&G	**4**	4	**14**	16
Other income (expenses), net	**(1)**	-	**(1)**	(4)
Adjusted EBITDA	**$ (9)**	$ (2)	**$ 5**	$ 15

Marketing and Trading Margin

Marketing and trading margin decreased $6 million to $(4) million in Q3 2017 compared to $2 million in Q3 2016; and decreased $15 million to $20 million year-to-date 2017 compared to $35 million during the same period in 2016. This reflected weaker market conditions in 2017 compared to 2016, specifically the impact of mild winter and summer weather and increased gas transportation infrastructure in the northeast United States that resulted in fewer optimization opportunities. This was partially offset by lower short-term fixed cost commitments for transportation and growth in the volume of business.

Emera Energy Generation

Adjusted EBITDA

Adjusted EBITDA for EEG is summarized in the following table:

For the millions of Canadian dollars						Three months ended September 30
	New England		Maritime Canada		Total	
	2017	2016	**2017**	2016	**2017**	2016
Energy sales	**$ 44**	$ 67	**$ 5**	$ 15	**$ 49**	$ 82
Capacity and other	**25**	12	**1**	-	**26**	12
Electricity revenue	**$ 69**	$ 79	**$ 6**	$ 15	**$ 75**	$ 94
Non-regulated fuel for generation and purchased power	**36**	47	**4**	12	**40**	59
Provincial, state and municipal taxes	**3**	3	**1**	-	**4**	3
OM&G	**8**	11	**5**	6	**13**	17
Adjusted EBITDA	**$ 22**	$ 18	**$ (4)**	$ (3)	**$ 18**	$ 15

For the millions of Canadian dollars						Nine months ended September 30
	New England		Maritime Canada		Total	
	2017	2016	**2017**	2016	**2017**	2016
Energy sales	**$ 132**	$ 257	**$ 44**	$ 57	**$ 176**	$ 314
Capacity and other	**52**	37	**2**	-	**54**	37
Electricity revenue	**$ 184**	$ 294	**$ 46**	$ 57	**$ 230**	$ 351
Non-regulated fuel for generation and purchased power	**112**	200	**34**	43	**146**	243
Provincial, state and municipal taxes	**8**	5	**1**	-	**9**	5
OM&G	**28**	31	**15**	17	**43**	48
Other income (expenses), net	**-**	-	**-**	1	**-**	1
Adjusted EBITDA	**$ 36**	$ 58	**$ (4)**	$ (2)	**$ 32**	$ 56

Adjusted EBITDA increased $3 million to $18 million in Q3 2017 from $15 million in Q3 2016 mainly due to higher capacity prices that came into effect for NEGG in June 2017, partially offset by less favourable market conditions, specifically mild summer weather in Q3 2017 compared to Q3 2016.

Year-to-date, adjusted EBITDA decreased $24 million to $32 million in 2017 from $56 million for the same period in 2016. Absent the $20 million in prior period state fuel taxes at NEGG, adjusted EBITDA would have decreased $44 million in 2017 compared to 2016. This was mainly due to lower realized energy margins in NEGG in 2017, reflecting more favourable short-term energy hedges in 2016 compared to 2017, less favourable market conditions, and lower energy sales volumes due to the unplanned outage at the Bridgeport Facility. These were partially offset by higher capacity prices that came into effect for NEGG in June 2017.

Operating Statistics

For the						Three months ended September 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2017	2016	**2017**	2016	**2017**	2016
New England	**1,100**	1,336	**91.5%**	87.0%	**44.7%**	55.5%
Maritime Canada	**79**	344	**86.8%**	79.2%	**11.3%**	49.9%
Total	**1,179**	1,680	**90.5%**	85.2%	**37.2%**	54.3%

For the						Nine months ended September 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2017	2016	**2017**	2016	**2017**	2016
New England	**2,496**	3,957	**77.5%**	91.7%	**34.2%**	55.2%
Maritime Canada	**660**	1,293	**71.4%**	87.1%	**31.5%**	63.0%
Total	**3,156**	5,250	**76.1%**	90.6%	**33.6%**	56.9%

(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 and Maritime Canada sales volumes and net capacity factor were lower quarter-over-quarter mainly due to less favourable market conditions in Q3 2017 which reduced opportunities for economic dispatch. Plant availability was up quarter-over-quarter due to fewer planned outage hours in Q3 2017 compared to Q3 2016.

NEGG and Maritime Canada sales volumes, plant availability and net capacity factor were lower year-over-year due to the impact of an unplanned outage at the Bridgeport Facility from mid-March 2017 to mid-June 2017, a planned outage at the Bayside Facility in Q2 2017 and less favourable market conditions in 2017 compared to 2016.

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	
	2017	2016	**2017**	2016
Operating revenues – regulated gas	**$ 14**	$ 1	**$ 39**	$ 26
Non-regulated operating revenue	**21**	11	**56**	27
Total operating revenue	**$ 35**	$ 12	**$ 95**	$ 53
Intercompany revenue (1)	**10**	9	**29**	29
Income from equity investments	**25**	18	**70**	66
Interest expense, net (2)	**71**	142	**217**	252
Adjusted contribution to consolidated net income (loss)	**$ (33)**	$ (151)	**$ (87)**	$ 19
After-tax mark-to-market gain (loss)	**1**	-	**2**	(116)
Contribution to consolidated net income (loss)	**$ (32)**	$ (151)	**$ (85)**	$ (97)
Adjusted contribution to consolidated earnings per common share – basic	**(0.15)**	(0.83)	**(0.41)**	0.12
Contribution to consolidated earnings per common share – basic	**$ (0.15)**	$ **(0.83)**	**$ (0.40)**	$ (0.60)
Adjusted EBITDA	**$ 32**	$ (59)	**$ 91**	$ 237

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

(2) Interest expense, net excludes a pre-tax mark-to-market gain of $2 million in Q3 and $3 million year-to-date 2017 (2016 – nil).

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) – 2016	**$ (151)**	**$ (97)**
Increased operating revenue - see Operating Revenues below	23	42
Decreased OM&G primarily due to 2016 costs related to the TECO Energy acquisition	76	87
Income from equity investments - see Income from Equity Investments below	7	4
2016 gain on sale of APUC common shares, pre-tax	-	(172)
2016 gain on conversion of APUC subscription receipts and dividend equivalents into APUC common shares, pre-tax	-	(63)
Increased other non-regulated direct costs related to increased project activity in Emera Utility Services	(8)	(30)
Decreased interest expense - see Interest Expense below	71	35
Decreased income tax recovery quarter-over-quarter primarily due to increased income before provision for income taxes; increased income tax recovery year-over-year primarily due to decreased income before provision for income taxes partially offset by the non-taxable portion of gains on APUC transactions in 2016	(44)	5
After-tax mark-to-market loss primarily related to the 2016 adjustments from forward contracts economically hedging the debenture offering and the translation of the USD cash balance	1	118
Other	(7)	(14)
Contribution to consolidated net income (loss) – 2017	**$ (32)**	**$ (85)**

Operating Revenues

Operating revenues increased $23 million to $35 million in Q3 2017 compared to $12 million in Q3 2016. Year-to-date, operating revenues increased $42 million to $95 million in 2017 compared to $53 million in the same period in 2016. The increases in both periods are primarily due to increased project activity in Emera Utility Services and funding commitments made to New Mexico related to the TECO Energy acquisition in Q3 2016.

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	
	2017	2016	**2017**	2016
LIL	**$ 9**	$ 6	**$ 27**	$ 16
NSPML	**10**	6	**26**	15
M&NP	**6**	6	**17**	17
APUC - sold in 2016	**-**	-	**-**	18
Income from equity investments	**$ 25**	$ 18	**$ 70**	$ 66

Income from equity investments increased $7 million to $25 million in Q3 2017 compared to $18 million in Q3 2016. Year-to-date, income from equity investments increased $4 million to $70 million in 2017 compared to $66 million during the same period in 2016. These variances were a result of higher earnings from the increased investment in NSPML and LIL, partially offset by the sale of APUC in 2016.

Interest Expense

Interest expense decreased $71 million to $71 million Q3 2017 compared to $142 million in Q3 2016 as a result of the conversion of the convertible debentures related to the TECO Energy acquisition in 2016. Year-to-date, interest expense decreased $35 million to $217 million in 2017 compared to $252 million for the same period in 2016 as a result of the conversion of the convertible debentures partially offset by the permanent USD denominated debt related to the TECO Energy acquisition in 2016.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through its investments in various regulated and non-regulated energy related entities and investments. 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 maintain solid credit metrics and 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.

Consolidated Cash Flow Highlights

Significant changes in the condensed consolidated statements of cash flows between the nine months ended September 30, 2017 and 2016 include:

millions of Canadian dollars		**2017**		2016		$ Change
Cash and cash equivalents, beginning of period	**$**	**404**	$	1,073	$	(669)
Provided by (used in):						
Operating cash flow before change in working capital		**956**		615		341
Change in working capital		**85**		252		(167)
Operating activities		**1,041**		867		174
Investing activities		**(1,271)**		(8,607)		7,336
Financing activities		**62**		7,157		(7,095)
Effect of exchange rate changes on cash and cash equivalents		**(15)**		(75)		60
Cash and cash equivalents, end of period	**$**	**221**	$	415	$	(194)

Cash Flow from Operating Activities

Refer to the Consolidated Income Statement and Operating Cash Flow Highlights earlier in the document for details.

Cash Flow Used In Investing Activities

Net cash used in investing activities decreased $7,336 million to $1,271 million for the nine months ended September 30, 2017 compared to $8,607 million during the same period in 2016 due to the acquisition of TECO Energy in 2016. This was partially offset by an increase in capital spending and proceeds from the sale of APUC common shares in 2016.

Capital expenditures for the nine months ended September 30, 2017, including AFUDC and net of proceeds from disposal of assets, were $1,091 million compared to $610 million during the same period in 2016. The increase was a result of the acquisition of TECO Energy and additional capital spending in NSPI, Emera Maine, Emera Energy and Corporate, offset by a reduction in capital spend in Emera Caribbean. Details of the capital spend are shown below:

- $645 million at Emera Florida and New Mexico (2016 – $246 million);
- $276 million at NSPI (2016 – $225 million);
- $77 million at Emera Maine (2016 – $51 million);
- $39 million at Emera Caribbean (2016 – $63 million);
- $34 million at Emera Energy (2016 – $22 million);
- $20 million in Corporate and Other (2016 – $3 million)

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $7,095 million to $62 million for the nine months ended September 30, 2017 compared to $7,157 million for the same period in 2016. The decrease was due to proceeds of the long-term debt issuance and convertible debentures related to the acquisition of TECO Energy in 2016. This was partially offset by increased 2017 borrowings under committed credit facilities.

Contractual Obligations

As at September 30, 2017, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2017	2018	2019	2020	2021	Thereafter	Total
Long-term debt	$ 396	$ 737	$ 1,084	$ 728	$ 2,084	$ 9,197	$ 14,226
Interest payment obligations (1)	240	584	564	520	471	5,877	8,256
Purchased power (2)	86	229	214	210	207	2,338	3,284
Transportation (3)	116	402	298	264	184	1,517	2,781
Pension and post-retirement obligations (4)	33	47	48	49	51	863	1,091
Fuel and gas supply	185	257	129	47	37	-	655
Long-term service agreements (5)	47	66	67	34	43	220	477
Asset retirement obligations	1	2	1	1	41	387	433
Equity investment commitments (6)	230	15	-	190	-	-	435
Leases and other (7)	22	40	11	10	6	64	153
Capital projects	78	225	87	-	-	-	390
Demand side management	18	90	10	-	-	-	118
Long-term payable	1	4	5	5	5	10	30
Convertible debentures	-	-	-	-	-	3	3
	$ 1,453	$ 2,698	$ 2,518	$ 2,058	$ 3,129	$ 20,476	$ 32,332

(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, 2017, 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, 2016. Credited service and earnings are assumed to be crystallized as at December 31, 2016. 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, 2016 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 in connection with the Federal Loan Guarantee to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to the Labrador Island Link Limited Partnership upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amounts as the projects advance through construction.
(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 and closer to the timing of the Muskrat Falls project completion.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $2.7 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	$ 700	$ 281	$ 419
Emera Florida and New Mexico - in USD - credit facilities	March 2018 - March 2022	1,300	754	546
NSPI – Operating credit facility	October 2021 – Revolver	600	258	342
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	28	52
Other – in USD – Operating credit facilities	Various	32	-	32

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, 2017.

Emera Florida and New Mexico

On November 2, 2017, TEC entered into a $300 million USD non-revolving term loan with a maturity date of November 1, 2018. The loan contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR plus a margin.

On November 1, 2017, TECO Energy/Finance repaid a $300 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

On March 22, 2017, TECO Energy/Finance extended the maturity date of its $300 million USD bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

On March 22, 2017, TEC extended the maturity date of its $325 million USD bank credit facility from December 17, 2018 to March 22, 2022, and reduced the existing letter of credit facility to $50 million USD from $200 million USD. There were no other significant changes in commercial terms from the prior agreement.

On March 22, 2017, NMGC extended the maturity date of its $125 USD million bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

On March 8, 2017, TECO Energy/Finance extended the maturity date of its $400 million USD term bank credit facility from March 14, 2017 to March 8, 2018 with no significant change in commercial terms from the prior agreement.

Emera Maine

On September 27, 2017 Emera Maine completed a 30-year $50 million USD senior unsecured notes issuance. The notes bear interest at a rate of 4.36% and will mature on September 27, 2047. Proceeds were used to repay maturing notes and for general corporate purposes.

BLPC

On September 1, 2017, BLPC's interest rate on their two $20 million BBD secured fixed rate senior notes maturing in 2020 and 2024 were reduced to 4.25% and 5.875% from 6.65% and 6.875%, respectively. Effective October 11th, 2017, interest on their $12 million BBD demand loan facility was reduced to 4% from 6.5%.

EBP

On July 4, 2017, Emera Brunswick Pipeline amended its Credit Agreement to extend the maturity from February 2019 to February 2021 with no change to commercial terms from the prior agreement.

NSPI

On June 28, 2017, NSPI amended its operating credit facility to extend the maturity from October 2020 to October 2021 and the debt to capitalization ratio from 0.65:1 to 0.70:1. All other terms of the agreement are the same.

GBPC

On March 21, 2017, GBPC amended its loan agreement with the addition of two non-revolving term credit facilities. There were no significant changes in commercial terms from the prior agreement. The combined total of these new facilities is for up to $45 million USD. At September 30, 2017 a total of $30 million USD was drawn against the new facilities.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2016 annual MD&A, with updates as noted below.

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian is 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 is approved, Cambrian is 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. As at September 30, 2017, TECO Energy had remaining indemnified bonds totaling $6 million ($5 million USD).

The amounts outlined above represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies.

The Company is working with Cambrian on the process to replace the remaining bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

Emera has a standby letter of credit in the amount of $21 million to guarantee the performance of the obligations of the EUS-Rokstad joint venture. The letter of credit has been extended, and now expires in November 2017. EUS-Rokstad is a joint venture between EUS and Rokstad Power, formed for the purpose of constructing the high voltage direct current components of NSPML's transmission line. Rokstad Power has issued a separate letter of credit to Emera for their portion of the work to be performed under the contract. EUS and Rokstad Power are jointly and severally liable for completion of the project.

Emera has standby letters of credit in the amount of $46 million USD for the benefit of secured parties in connection with a refinancing of the Bear Swamp joint venture and also 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 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 2018 and is renewed annually. The amount committed as at September 30, 2017 was $51 million.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Enterprise Resource Planning System Risk

In August 2017, Emera's Canadian operating affiliates updated their financial information systems through the implementation of an integrated ERP system. The Company has adopted a detailed plan to address the risks inherent in the implementation of a new financial information system. Potential deficiencies in the design and implementation of the new ERP system could affect Emera's ability to monitor its business, pay its suppliers and prepare its financial statements accurately and on a timely basis. Emera continues to manage this risk through a dedicated project post-implementation activities and hyper-care team, executive oversight and a detailed governance structure. Consultants, with extensive ERP expertise, have and will continue to assist in project management, post-implementation, hyper-care and training.

There have been no other material changes in Emera's risk management profile and practices from those disclosed in the Company's 2016 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** **2017**		December 31 2016
Derivative instrument assets (current and other assets)	**$**	**8**	$	10
Derivative instrument liabilities (current and long-term liabilities)		**(10)**		(27)
Net derivative instrument assets (liabilities)	**$**	**(2)**	$	(17)

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			
		2017		2016		**2017**		2016
Operating revenues – regulated	**$**	**(1)**	$	(3)	**$**	**(7)**	$	(8)
Non-regulated fuel for generation and purchased power		**-**		(1)		**3**		2
Income from equity investments		**-**		-		**-**		(1)
Effective net gains (losses)	**$**	**(1)**	$	(4)	**$**	**(4)**	$	(7)

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

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**September 30 2017**		December 31 2016
Derivative instrument assets (current and other assets)	**$**	**142**	$	229
Regulatory assets (current and other assets)		**13**		11
Derivative instrument liabilities (current and long-term liabilities)		**(16)**		(12)
Regulatory liabilities (current and long-term liabilities)		**(140)**		(231)
Net asset (liability)	**$**	**(1)**	$	(3)

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		
		2017		2016		**2017**		2016
Regulated fuel for generation and purchased power (1)	**$**	**1**	$	(2)	**$**	**14**	$	-
Net gains (losses)	**$**	**1**	$	(2)	**$**	**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.

Held-for-trading ("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 2017**		December 31 2016
Derivative instruments assets (current and other assets)	**$**	**77**	$	37
Derivative instruments liabilities (current and long-term liabilities)		**(202)**		(434)
Net derivative instrument assets (liabilities)	**$**	**(125)**	$	(397)

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		
		2017		2016		**2017**		2016
Operating revenue - non-regulated	**$**	**26**	$	(38)	**$**	**409**	$	219
Non-regulated fuel for purchased power		**(1)**		(3)		**6**		-
Net gains (losses)	**$**	**25**	$	(41)	**$**	**415**	$	219

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 2017**	December 31 2016
Derivative instrument assets (current and other assets)	**$ 2**	$ -
Derivative instrument liabilities (current and long-term liabilities)	**-**	(2)
Net derivative instrument assets (liabilities)	**$ 2**	$ (2)

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Interest expense, net	**$ 2**	$ -	**$ 3**	$ -
Other income (expense)	**-**	15	**-**	(87)
Total gains (losses)	**$ 2**	$ 15	**$ 3**	$ (87)

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, 2017, to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Change in ICFR

In August 2017, Emera upgraded its Enterprise Resource Planning (ERP) system and other associated financial systems in the Company’s Canadian operating entities. This upgrade, which resulted in a material change to the internal controls over financial reporting, was designed to automate certain manual processes and standardize business processes and reporting across the impacted entities. Emera and its affiliates have made appropriate changes to internal controls and procedures, as is expected with a major system implementation, and is evaluating the effectiveness of these controls as part of their financial compliance program prior to the December 31, 2017 year-end.

There were no other changes in the Company’s ICFR during the quarter ended September 30, 2017, that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting except as noted above.

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 was no material change in the nature of the Company's critical accounting estimates from those disclosed in the Company's 2016 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

The Company considers the applicability and impact of all Accounting Standard Updates ("ASU") issued by the 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 2016 audited consolidated financial statements, with the exception of the items noted below.

Revenue from Contracts with Customers
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework, codified as Accounting Standards Codification ("ASC") Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect scope improvements and practical expedients. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018, using the modified retrospective approach.

The Company implemented a revenue recognition project plan in 2016. In Q1 2017, the Company concluded that the accounting for contributions in aid of construction will be out of the scope of the new standard. In Q2 2017, the Company completed an analysis of material regulated revenue streams and collectability risk and has concluded that there will be no material changes on adoption of this standard. In Q3 2017, the Company completed an analysis of material unregulated revenue streams and concluded that there will be no material changes on adoption of this standard. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company's information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company continues to monitor the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force for developments.

Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance will be 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 will elect 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 increase in volatility of Other income (expense), net as a result of the remeasurement of equity investments is not expected to be significant. The Company will adopt this guidance effective January 1, 2018 with a cumulative-effect adjustment to retained earnings in the Consolidated Balance Sheet.

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. In Q3 2017, the Company implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. This includes evaluating the available practical expedients, calculating the lease asset and liability balances associated with individual contractual arrangements and assessing the disclosure requirements. The Company continues to monitor FASB amendments to ASC Topic 842.

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 Consolidated Statements of Income outside of income from operations. Only the service cost component will be eligible for capitalization as property, plant and equipment under this guidance. This guidance will be 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 Consolidated Statements of Income and prospectively for the guidance limiting capitalization. The Company is currently evaluating the impact of the adoption of this standard on the consolidated financial statements, including the eligibility for capitalization of the other components of net benefit cost given the application of ASC 980 *Regulated Operations*. The Company will adopt this guidance effective January 1, 2018.

Targeted Improvements to Accounting for Hedging Activities
In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities* which amends the hedge accounting recognition and presentation requirements in ASC 815. This standard improves the transparency and understandability of information about an entity’s risk management activities by better aligning the entity’s financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted, and is required to be applied using a modified retrospective approach. The Company is currently evaluating 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 2017**	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015
Operating revenues	**$ 1,427**	$ 1,469	$ 1,857	$ 1,513	$ 1,387	$ 499	$ 877	$ 732
Net income (loss) attributable to common shareholders	**81**	101	312	70	(95)	208	44	192
Adjusted net income attributable to common shareholders	**118**	117	152	104	14	238	120	87
Earnings per common share – basic	**0.38**	0.47	1.48	0.34	(0.52)	1.39	0.30	1.31
Earnings per common share – diluted	**0.38**	0.47	1.47	0.34	(0.52)	1.38	0.30	1.30
Adjusted earnings per common share – basic	**0.55**	0.55	0.72	0.51	0.08	1.59	0.81	0.59

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. Historically, the first quarter has generally been the strongest because a significant portion of the Company's operations are in northeastern North America, where winter is the peak electricity usage season. However, with the addition of Emera Florida and New Mexico, the third quarter has provided stronger 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 adjustments.