Management’s Discussion & Analysis

As at November 7, 2016

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 of 2016 relative to 2015; and its financial position as at September 30, 2016 relative to December 31, 2015. To enhance shareholders’ understanding, certain multi-year historical financial and statistical information is also presented. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated unaudited condensed consolidated interim financial statements and supporting notes as at and for the nine months ended September 30, 2016; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2015. 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	Florida Public Service Commission ("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 the Federal Energy Regulatory Commission ("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 Business Overview 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.

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 harbor 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 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; integration risk with respect to Emera's acquisition of TECO Energy Inc., ("TECO Energy"); enterprise resource planning implementation 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 which could reduce demand for electricity; weather; commodity price risk; construction and development 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.

Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview, Business Overview, followed by Non-GAAP Financial Measures, Significant Items Affecting Earnings, and the Consolidated Financial Review; then presents information specific to Emera's consolidated subsidiaries and investments.

The company's activities are carried out through six business segments discussed below:

- Emera Florida and New Mexico includes Tampa Electric Company (consisting of two divisions: Tampa Electric and Peoples Gas System), New Mexico Gas Company, parent company TECO Energy, and TECO Finance, Inc. ("TECO Finance"), a wholly owned financing subsidiary of TECO Energy;
- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and its parent company, Emera (Caribbean) Incorporated ("ECI"), GBPC, and Lucelec;
- Emera Energy includes Emera Energy Services ("EES"); Emera Energy Generation ("EEG") which includes Bridgeport Energy, Tiverton Power and Rumford Power ("New England Gas Generating Facilities" ("NEGG")), Brooklyn Power Corporation ("Brooklyn Energy" or "Brooklyn"); Bayside Power Limited Partnership ("Bayside Power" or "Bayside") and Bear Swamp Power Company LLC ("Bear Swamp");
- Corporate and Other includes:
    - Interest revenue on intercompany financings and costs associated with corporate activities that are not directly allocated to the operations of Emera's consolidated subsidiaries and investments;
    - Costs related to the TECO Energy acquisition;
    - Pipelines, including Brunswick Pipeline and M&NP;
    - Emera Utility Services Inc. ("Emera Utility Services");
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL") and its investments in NSPML and LIL;
    - Emera Reinsurance Limited;
    - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States;
    - Emera US Finance LP, a wholly owned financing subsidiary of Emera. This company issued USD denominated senior, unsecured notes for the purpose of acquiring TECO Energy;
    - Emera's investment in Algonquin Power & Utilities Corp. ("APUC") and;
    - Other investments

The Liquidity and Capital Resources, including Consolidated Cash Flow Highlights, Transactions with Related Parties, Risk Management and Financial Instruments, Disclosure and Internal Controls, Critical Accounting Estimates, Changes in Accounting Policies and Practices and Summary of Quarterly Results sections of the MD&A are presented on a consolidated basis.

INTRODUCTION AND STRATEGIC OVERVIEW

Emera Incorporated is a geographically diverse energy and services company, targeting eight-per-cent annual dividend growth through 2020. The Company invests in electricity generation, electricity transmission and distribution, gas transmission and distribution, and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States and the Caribbean.

Regulated utilities are the foundation of Emera's business, providing the Company with strong and consistent earnings. 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. In Florida and New Mexico the Company is evaluating 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 help 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.

Since its formation in 2003, Emera Energy has become an active participant in the northeastern United States electricity and natural gas markets. It has built a strong marketing, trading and asset management business, based on comprehensive market knowledge, focus on customer service and robust risk management. The integration and performance of the three NEGG Facilities purchased in 2013 has contributed significantly to the success of Emera Energy.

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, environmental concerns (including demand for new, less carbon-intensive and renewable generation), lower-cost natural gas, growing demand for new electric heating solutions, and the requirement for large-scale transmission projects to deliver new energy sources to customers. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving replacement of higher-carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver that energy to market.

Emera has partnerships and relationships throughout the regions in which it operates and has established a diverse investment and operations profile that links its assets and capabilities in those regions. At the core of Emera's strategy is the ability to leverage these particular linkages and adjacencies to create solutions for customers and investment opportunities for the Company.

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

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

Emera targets achieving 75 to 85 per cent of its adjusted net income (a non-GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable earnings and cash flows that fund dividends, reinvestment and are reflective of the Company's risk tolerance. The Company is expected to achieve this adjusted net income target with the July 1, 2016 close of its acquisition of TECO Energy.

Emera has grown its asset base to enable growth and 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. This was demonstrated in Emera's financing of the TECO Energy acquisition. 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.

BUSINESS OVERVIEW

Energy markets across North America are affected by a number of trends that shape the environment in which energy and utility companies are operating. Some of these trends are short-term or cyclical, while others evolve to have a significant long-term impact on businesses and stakeholders across the sector.

Among the key trends influencing Emera's long-term strategy is the increasing expectation by customers and policy-makers for a permanent reduction in the carbon-equivalent levels of electricity generation. This advocacy drive for cleaner, renewable sources of electricity has become a defining trend in the industry in recent years, not just in the markets Emera serves but on a global basis. While it is still unclear whether economic volatility and lower fossil fuel prices will slow the pace of this transformation, its 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 and hydro generation, and natural gas infrastructure, is likely to continue across the sector despite the substantial cost differential with fossil fuels.

The transformation in generation and fuel selection also has a significant impact on the requirement for new transmission infrastructure. Increasingly, in addition to the traditional issues of infrastructure life expectancy and changing technology, infrastructure renewal planning must now also take into account the changing energy landscape. Gas extraction from the Marcellus Shale region of the United States, major new hydro developments in Newfoundland and Labrador, and development of new wind farms in northern New England and Atlantic Canada (to name a few) require significant new transmission infrastructure to bring this energy to market.

The capital spending requirements related to new infrastructure will need to be addressed in the context of the intense focus of customers and regulators on electricity pricing and affordability. Going forward, the ability of energy companies to achieve their growth objectives, environmental targets and other goals, will depend on their ability to address price and affordability.

As technology advances, so does the availability and demand for affordable new mechanisms that allow consumers to have more control over their energy usage and for utilities to introduce more efficient energy solutions for their customers. This includes grid modernization or 'smart grid' advances that, when combined with in-home products such as heat pumps and electric thermal storage units, have the potential to significantly increase energy efficiency for consumers while allowing utilities to better manage peak load demand. In addition, like wind turbine technology, advancements in solar technology have reduced solar generation costs significantly, bringing them more in line with the cost of fossil fuel generation in some higher-cost jurisdictions. This gives rise to customer expectations that they will be able to benefit from options such as distributed generation. Continued and advancing development of energy storage technology will further transform and support the efficient and practical utilization of renewables and will facilitate the integration of more distributed generation.

These and other trends create opportunities and challenges for businesses, regulators, investors and other stakeholders within the energy sector, and are expected to drive increased regional cooperation and interconnection within the energy industry. Whether it is the need to transport natural gas and electricity from disparate regions to markets on the eastern seaboard, or the need to gain efficiencies by coordinating electricity generation and dispatch across multiple jurisdictions, inter-regional cooperation has emerged as an important trend in itself.

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, as detailed below:

Non-GAAP measure	GAAP measure
Adjusted net income attributable to common shareholders or adjusted net income	Net income attributable to common shareholders
Adjusted earnings per common share – basic	Earnings per common share – basic
Adjusted contribution to consolidated net income	Contribution to consolidated net income
Adjusted income before provision for income taxes	Income before provision for income taxes
Adjusted contribution to consolidated earnings per common share – basic	Contribution to consolidated earnings per common share – basic
EBITDA	Net income
Adjusted EBITDA	Net income
Electric margin and gas margin	Income from operations

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;
- 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 related to the effect of TECO Energy acquisition USD-denominated currency and forward contracts. 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") for the TECO Energy acquisition.

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 Highlights section, Emera Energy – Review of 2016 and Corporate and Other – Review of 2016.

The following is a reconciliation of 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	
	2016	2015	**2016**	2015
Net income (loss) attributable to common shareholders	**$ (95)**	$ 35	**$ 157**	$ 205
After-tax mark-to-market gain (loss)	**$ (109)**	$ 12	**$ (214)**	$ (38)
Adjusted net income attributable to common shareholders	**$ 14**	$ 23	**$ 371**	$ 243
Earnings per common share – basic	**$ (0.52)**	$ 0.24	**$ 0.98**	$ 1.41
Adjusted earnings per common share – basic	**$ 0.08**	$ 0.16	**$ 2.31**	$ 1.67

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, make capital expenditures and finance working capital requirements.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to adjusted net income calculations, this measure represents EBITDA absent the income effect of Emera's mark-to-market adjustments, as previously discussed.

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies, but in management's view it appropriately reflects Emera's specific financial condition. 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.

EBITDA and Adjusted EBITDA Reconciliation

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Net income (loss) (1)	**$ (76)**	$ 57	**$ 195**	$ 253
Interest expense, net	**233**	49	**416**	142
Income tax expense (recovery)	**(44)**	12	**(16)**	72
Depreciation and amortization	**204**	85	**376**	252
EBITDA	**317**	203	**971**	719
Mark-to-market gain (loss), excluding income tax and interest	**(158)**	22	**(275)**	(53)
Adjusted EBITDA	**$ 475**	$ 181	**$ 1,246**	$ 772

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

Electric Margin and Gas Margin

"Electric margin" and "Gas margin" are non-GAAP financial measure used to show the amounts that Emera's regulated utilities retain to recover non-fuel and non-clause related costs. Prudently incurred fuel costs are recovered from customers, except at Domlec, where substantially all prudently incurred fuel costs are passed to customers through the fuel pass-through mechanism. Management believes measuring electric and gas margin shows the portion of these utilities' revenues that directly contribute to Emera's income as distinguished from the portion of revenues that are managed through fuel adjustment and other clause mechanisms, which have a minimal impact on income.

Emera Energy also reports “Non-regulated electric margin” because the sales price of electricity and the cost of natural gas used to generate it are highly correlated. However, their absolute values can vary materially over time. Emera Energy believes that “Non-regulated electric margin”, as the net result, provides a meaningful measure of business performance in addition to the absolute values of sales and fuel expenses, which are also reported.

Electric margin and gas margin, as calculated by Emera, may not be comparable to the electric margin measures of other companies, but in management’s view appropriately reflects Emera’s specific condition. This measure is not intended to replace “Income from operations” which, as determined in accordance with GAAP, is an indicator of operating performance. Electric margin and Gas margin are discussed further in the Emera Florida and New Mexico – Electric and Gas Margin, the NSPI – Electric Margin, the Emera Caribbean – Electric Margin and the Emera Energy – Adjusted EBITDA sections.

Significant Items Affecting Earnings

2016

Acquisition Related Costs

Emera incurred after-tax costs related to its acquisition of TECO Energy (“the Acquisition”), including legal, banking and advisory, stipulation commitments, accelerated vesting of TECO Energy stock based compensation, pre closing financing and foreign exchange costs totaling $119 million ($0.65 per common share) in Q3 2016 (Q3 2015 – $20 million) and $179 million year-to-date ($1.12 per common share) (2015 – $20 million). All acquisition costs have been recognized in the Corporate and Other segment.

As discussed and included below in “After-Tax-Mark-to-Market-Losses”, the foreign currency earnings effect related to the Convertible Debentures USD cash balance and the associated forward contracts was nil in Q3 2015 and a mark-to-market after-tax loss of $116 million year-to-date in 2016 (2015 – nil) in “Other income (expenses), net”.

In Q3 2016 substantially all of Emera’s Convertible Debentures were converted to equity, and as a result, Emera recognized the difference between Emera’s closing share price on the issuance date of the Convertible Debentures and their exercise price (the “Beneficial Conversion Feature discount”) resulting in a cost of $62 million ($43 million after-tax or $0.24 per common share). This cost is included in the acquisition expense noted above.

Investment in APUC

On May 24, 2016, Emera completed the sale of 50.1 million common shares of 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. After the conversion, Emera’s has a 4.7 per cent 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

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. This includes $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" in Q2 2016.

After-Tax Mark-to-Market Losses

After-tax mark-to-market losses increased $121 million to $109 million in Q3 2016 compared to $12 million gain in Q3 2015 and increased $176 million to $214 million year-to-date in 2016 compared to $38 million loss for the same period in 2015. The increased mark-to market losses in the quarter are primarily due to changes in existing positions on long-term contracts and the amortization of 2015 gas transportation assets at Emera Energy. To explain further, at inception of a long-term contract the unrealized mark-to-market adjustment on the commodity portion of the contract is offset fully by the value of a corresponding gas transportation asset. Subsequent changes in gas prices result in unrealized mark-to-market gains or losses recorded in earnings, with the transportation assets being amortized evenly over the contract term. The difference between these items results in unrealized mark-to-market gains or losses in earnings, however the mark-to-market adjustments and transportation assets ultimately reduce to zero at the end of the contract term.

In addition, the translation of the TECO Energy related Convertible Debentures USD-denominated currency partially offset by the reversal of 2015 mark-to-market losses in 2016 and changes in gas and power contract positions in Emera Energy also contributed to the year-over-year increase in mark-to-market losses.

2015

Barbados Light & Power Company Limited ("BLPC") Restructuring Costs

BLPC recorded severance costs of $8 million ($6 million USD) relating to corporate restructuring, which was recorded in "Operating, maintenance and general" ("OM&G") in Q2 2015. The after-tax effect on Emera's Consolidated Net Income in Q2 2015, at Emera's then 80.7 per cent ownership of ECI, was $5 million ($0.04 per common share).

Sale of Northeast Wind Partnership II, LLC ("NWP") Equity Investment

On January 29, 2015, Emera completed the sale of its 49-per-cent interest in NWP for $282 million ($223 million USD). This sale resulted in a pre-tax gain of $19 million or $0.13 per common share (after-tax gain of $12 million or $0.08 per common share), which was recorded in "Other income (expenses), net" in Q1 2015.

CONSOLIDATED FINANCIAL REVIEW

Below is a table highlighting significant changes between adjusted net income from 2015 to 2016.

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2015	**$ 23**	**$ 243**
Emera Florida and New Mexico	109	109
Emera Caribbean	11	22
NSPI	10	6
Gain on sale of APUC common shares	-	146
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	-	53
Gain on BLPC SIF regulatory liability	-	43
Acquisition and financing costs related to the acquisition of TECO Energy	(99)	(159)
TECO Energy post-acquisition financing costs	(49)	(49)
Emera Energy	(15)	(52)
2015 gain on the sale of NWP	-	(12)
Emera Energy's recognition of fuel taxes for 2013 through March 2016	-	(12)
Other	24	33
Adjusted net income – 2016	**$ 14**	**$ 371**

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Operating revenues	**$ 1,387**	$ 643	**$ 2,764**	$ 2,058
Income from operations	**76**	91	**347**	359
Net income (loss) attributable to common shareholders	**(95)**	35	**157**	205
After-tax mark-to-market gain (loss)	**(109)**	12	**(214)**	(38)
Adjusted net income attributable to common shareholders	**$ 14**	$ 23	**$ 371**	$ 243
Earnings per common share – basic	**$ (0.52)**	$ 0.24	**$ 0.98**	$ 1.41
Earnings per common share – diluted	**$ (0.52)**	$ 0.24	**$ 0.97**	$ 1.40
Adjusted earnings per common share – basic	**$ 0.08**	$ 0.16	**$ 2.31**	$ 1.67
Dividends per common share declared	**$ 1.0450**	$ 0.8750	**$ 1.9950**	$ 1.6625
Adjusted EBITDA	**$ 475**	$ 181	**$ 1,246**	$ 772

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
Operating Unit Contributions to Adjusted Net Income	**2016**	2015	**2016**	2015
Emera Florida and New Mexico	**109**	-	**109**	-
NSPI	**$ 15**	$ 5	**$ 96**	$ 90
Emera Maine	**17**	15	**36**	40
Emera Caribbean	**24**	13	**92**	27
Emera Energy	**-**	15	**19**	95
Corporate and Other	**(151)**	(25)	**19**	(9)
Adjusted net income attributable to common shareholders	**$ 14**	$ 23	**$ 371**	$ 243
After-tax mark-to-market gain (loss)	**(109)**	12	**(214)**	(38)
Net income (loss) attributable to common shareholders	**$ (95)**	$ 35	**$ 157**	$ 205

For the millions of Canadian dollars	Nine months ended September 30	
	2016	2015
Operating cash flow before changes in working capital	**$ 615**	$ 591
Change in working capital	**252**	(29)
Operating cash flow	**$ 867**	$ 562
Investing cash flow	**$ (8,607)**	$ (101)
Financing cash flow	**$ 7,157**	$ 76

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Working capital	**$ (68)**	$ 600
Total assets	**$ 27,954**	$ 12,039

Q3 Consolidated Income Statement Highlights

Operational Results

Income from operations decreased $15 million to $76 million in Q3 2016 compared to $91 million in Q3 2015 primarily due to higher mark-to-market losses and increased costs related to the acquisition of TECO Energy, partially offset by the contribution of Emera Florida and New Mexico.

Total operating revenues increased $744 million to $1,387 million in Q3 2016 compared to $643 million in Q3 2015, primarily due to:

- $959 million increase from Emera Florida and New Mexico;
- $179 million decrease from changes in mark-to-market impacts;
- $13 million decrease in NSPI primarily as a result of decreased sales volumes and electricity pricing.

Total operating expenses increased $759 million to $1,311 million in Q3 2016 compared to $552 million in Q3 2015, primarily due to the addition of expenses from Emera Florida and New Mexico and increased TECO Energy acquisition and financing costs.

Other income (expenses), net

Other income in Q3 2016 increased $11 million to $14 million compared to $3 million in the same period in 2015. This was primarily due to the contribution from Emera Florida and New Mexico.

Interest expense, net

Interest expense, net increased $184 million in Q3 2016 to $233 million compared to $49 million in the same period in 2015, primarily due to the Beneficial Conversion Feature recognized on conversion of the Convertible Debenture, financing related to the TECO Energy acquisition and the interest expense from Emera Florida and New Mexico.

Income tax expense (recovery)

Income tax expense decreased $56 million to a $44 million recovery compared to $12 million expense for the same period in 2015 primarily due to decreased income before provision for income taxes.

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

Operational Results

Income from operations decreased $12 million to $347 million year-to-date ("YTD") in 2016 compared to $359 million during the nine months in 2015. This is primarily due to mark-to-market losses of $84 million, increased costs related to the acquisition of TECO Energy, decreased margin at the NEGG Facilities, including recognizing a $20 million liability for state tax on natural gas sales made from November 2013 through March 2016, and decreased income from operations at NSPI. These decreases were partially offset by the contribution from Emera Florida and New Mexico.

Total operating revenues increased $706 million to $2,764 million year-to-date in 2016 compared to $2,058 million in 2015 primarily due to:

- $959 million increase from Emera Florida and New Mexico;
- $89 million decrease from changes in mark-to-market impacts;
- $75 million decrease at NSPI as a result of decreased sales volumes due to weather and lower growth;
- $41 million decrease at the NEGG Facilities reflecting lower hedged and market commodity prices, partially offset by fewer outage hours at Bridgeport Energy in 2016.

Total operating expenses increased $718 million to $2,417 million year-to-date in 2016 compared to $1,699 million for the same period in 2015. This was primarily a result of expenses from Emera Florida and New Mexico and increased costs related to the acquisition of TECO Energy, partially offset by decreased fuel costs at NSPI reflecting lower commodity prices and lower load due to weather.

Other income (expenses), net

Other income increased $143 million to $169 million year-to-date in 2016 compared to $26 million for the same period in 2015. This was primarily due to a $172 million pre-tax gain on the sale of 50.1 million common shares of APUC, a $63 million pre-tax gain on conversion of 12.9 million APUC subscription receipts and dividend equivalents, and a $53 million gain on the BLPC SIF regulatory liability. This was partially offset by mark-to-market losses relating to the TECO Energy acquisition related USD-denominated currency and forward contracts and the 2015 gain on the sale of NWP.

Interest expense, net

Interest expense, net increased $274 million year-to-date in 2016 to $416 million compared to $142 million in 2015. This was primarily due to the new financing related to the TECO Energy acquisition, interest and the Beneficial Conversion Feature on the Convertible Debentures, as well as interest expense from Emera Florida and New Mexico.

Income tax expense (recovery)

Income tax expense decreased $88 million to a $16 million recovery year-to-date compared to a $72 million expense for the same period in 2015 primarily due to decreased income before provision for income taxes, the non-taxable portion of gains on APUC transactions and deferred income taxes on regulated income recorded as regulatory assets and liabilities. This was partially offset by the non-deductible portion of mark-to-market losses on USD-denominated currency and forward contracts related to the TECO Energy acquisition.

Net cash provided by operating activities

Net cash provided by operating activities year-to-date in 2016 increased $305 million to $867 million compared to $562 million during the same period in 2015.

Cash from operations before changes in working capital increased by $24 million primarily due to the contribution from Emera Florida and New Mexico, partially offset by acquisition and financing costs related to TECO Energy, decreased margin at the NEGG Facilities and lower distributions at Bear Swamp.

Changes in working capital increased operating cash flows by $281 million primarily due to favourable changes in posted margin at NSPI and Emera Energy Services, the contribution from Emera Florida and New Mexico, the timing of income taxes at NSPI and Emera Energy Services, and decreased fuel inventory and receivables as a result of lower sales at NSPI.

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, it manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. Emera does not utilize derivative financial instruments for 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 earnings are recorded in US dollar currency.

millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Emera Florida and New Mexico	**$ 84**	$ -	**$ 84**	$ -
Emera Energy (1)	**4**	12	**20**	78
Emera Maine	**13**	11	**27**	32
Emera Caribbean	**19**	11	**71**	21
	120	34	**202**	131
Corporate and Other (2)	**(29)**	3	**(30)**	5
Total	**$ 91**	$ 37	**$ 172**	$ 136
FX rate for period	**$ 1.29**	$ 1.30	**$ 1.33**	$ 1.26

(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 Outlook

The acquisition of TECO Energy has strengthened Emera's business mix and allowed the Company to meet its strategic goal of having 75 to 85 per cent of its adjusted net income come from regulated operations. TECO Energy adds diversity to Emera's operations, meets Emera's strategic objective of expanding Emera's operations to include gas distribution services, and expands Emera's markets into growth regions. TECO Energy's operations and opportunities align well with Emera's strategy to invest in the transformation of electricity generation from higher to lower carbon intensity and providing cleaner and affordable energy solutions for customers. The addition of these regulated businesses will result in a material increase in earnings and cash flow as compared to the expected financial results prior to the acquisition.

Emera's operations are affected by the US dollar relative to the Canadian dollar. The effect on Emera's income is noteworthy, as it is expected that approximately 70 per cent of Emera's future adjusted net income will be derived from subsidiaries with a US functional currency. Emera's consolidated net income and cash flows will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar as a result of the TECO Energy acquisition.

Emera Florida and New Mexico

Emera Florida and New Mexico includes the following:

- TECO Energy, the parent company of the companies discussed below.
- TEC, which 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.
  - PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida.
- NMGC, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico.
- TECO Finance, a financing subsidiary of TECO Energy.

Tampa Electric

With over $6.8 billion USD of assets and approximately 730,000 customers, Tampa Electric owns 4,730 megawatts ("MW") of generating capacity, of which 60 per cent is natural gas fired, 35 per cent is conventional coal fired and 5 per cent coal and petcoke using integrated gasification combined cycle technology. Tampa Electric owns approximately 2,100 kilometers of transmission facilities and over 18,000 kilometers of distribution facilities.

Tampa Electric is regulated by the FPSC under a cost-of-service model, with rates established to recover prudently incurred costs of providing electricity service to customers and to provide an appropriate return consistent with investments of comparable risk to investors. Tampa Electric's target regulated return on equity ("ROE") range is currently 9.25 per cent to 11.25 per cent, on an allowed equity in the capital structure of 54 per cent. Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services, and accounting practices.

Tampa Electric has a fuel-recovery clause, approved by the FPSC, allowing recovery of actual fuel costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs for generation and purchased power and certain fuel-related costs ("Fuel Costs") and amounts recovered from customers through electricity rates are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year. Tampa Electric has an environmental cost recovery clause which allows the company to earn a return on investments in new facilities to comply with new environmental regulations and to recover the costs to operate and maintain these facilities. Through its conservation cost recovery clause, Tampa Electric also offers its customers a comprehensive array of residential and commercial programs that have enabled the company to meet its required demand side management goals, reduce weather-sensitive peak demand and conserve energy.

Florida utilities must obtain franchises to operate in certain municipalities. Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates ranging from September 2017 through August 2043 and are expected to be renewed under similar terms and conditions.

Peoples Gas System

With approximately $1.1 billion USD of assets and 370,000 customers, PGS's system includes 19,500 kilometers of natural gas mains and 11,100 kilometers of service lines. Gas mains are distribution lines that serve as a common source of supply for more than one service line. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) is 1.8 billion therms.

PGS is regulated by the FPSC under a cost-of-service model, with rates established to recover prudently incurred costs of providing gas distribution service to customers, and to provide an appropriate return consistent with investments of comparable risk to investors. PGS's allowed ROE range is 9.75 per cent to 11.75 per cent.

New Mexico Gas Company, Inc.

With over $0.8 billion USD of assets and approximately 518,000 customers, NMGC serves about 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,600 kilometers of transmission lines and 16,400 kilometers of mains. Annual natural gas throughput is approximately 775 million therms. NMGC's largest concentration of customers (approximately 360,000) is in the region known as the Central Rio Grande Corridor, which includes the communities of Albuquerque, Belen, Rio Rancho and Santa Fe.

NMGC is regulated by the NMPRC under a cost-of-service model, with rates established to recover prudently incurred costs of providing gas distribution service to customers, and to provide an appropriate return consistent with investments of comparable risk to investors. NMGC's rates were established in a 2012 rate case settlement and are frozen until December 31, 2017 per the NMPRC June 2016 order (the "Order") approving Emera's acquisition of TECO Energy. Under the Order, NMGC will also provide customer credits of $4 million USD annually through June 30, 2018.

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

The Florida utilities anticipate earnings within their allowed ROE range in 2016 and the utilities, including NMGC, expect earnings and rate base to be generally consistent with prior years, as a result of continued customer growth and a focus on cost control.

From July 1, 2016, the date of Emera's acquisition, to the end of 2016, Emera Florida and New Mexico expects to invest approximately $435 million USD in capital projects. These include expenditures related to the Polk Power Station expansion and implementing a new customer relationship management system in Florida.

Tampa Electric is also investing in a 23 MW utility scale solar photo voltaic project at its Big Bend Station, with completion expected by early 2017. This will be the largest solar project in the Tampa Bay area.

NSPI

NSPI is a fully-integrated regulated electric utility with assets of approximately $5 billion. It is the primary electricity supplier in Nova Scotia providing electricity generation, transmission and distribution services to approximately 509,000 customers. NSPI's target regulated return on equity ("ROE") range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40.0 per cent. NSPI owns 2,483 MW of generating capacity, of which approximately 43 per cent is coal fired, 28 per cent is natural gas and/or oil, 19 per cent is hydro and wind, 7 per cent is petcoke and 3 per cent is biomass-fueled generation. NSPI also owns approximately 5,000 kilometers of transmission facilities and 27,000 kilometers of distribution facilities.

NSPI's earnings are most directly impacted by the range of rate of return on equity and capital structure approved by the UARB, the prudent management and approved recovery of operating costs, load, the approved recovery of regulatory deferrals; and the timing and amount of capital expenditures.

While NSPI has experienced an unseasonably warm heating season with increased storm activity in Q1 2016, NSPI anticipates earning within its allowed ROE range in 2016 and expects its earnings and rate base to generally be consistent with prior years.

Over the past several years, the requirement to reduce Nova Scotia's reliance upon greenhouse gas emitting sources of energy has resulted in NSPI making a significant investment in renewable energy sources and purchasing third party renewable energy. In December 2015, the Electricity Plan Act was enacted by the Province of Nova Scotia with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. In accordance with the Electricity Plan Act NSPI filed with the UARB a three-year stability plan for fuel costs in Q1 2016. NSPI also announced it will not file a general rate application for non-fuel costs for the 2017 to 2019 period. This was a result of NSPI continuing to work towards rate stability for customers through a focused effort on operating costs, productivity levels and service improvements.

On July 19, 2016, the UARB approved a Consensus Agreement between NSPI and customer representatives related to the stability plan for Fuel Costs for 2017 through 2019 which results in an average annual increase of 1.1 per cent for each of these three years. Subsequently, certain customer representatives requested changes to certain classes of rates. If the rates requested are approved by the UARB, the average annual rate increase of 1.1 per cent in the Consensus Agreement would increase to a 1.5 per cent average increase for each of these three years. A decision is expected from the UARB in the fourth quarter of 2016.

In 2015, NSPI filed an application with the UARB for the approval of a market framework to enable independent renewable energy producers licensed by the UARB to sell directly to retail customers. The UARB issued a decision in 2016 approving the Company's proposed framework subject to small revisions. Potential retailers must apply to the UARB for approval of a license to sell low-impact renewable electricity generated in Nova Scotia. Licensed retailers who enter this retail market must pay tariffs to use NSPI's systems for delivering their renewable energy, to ensure the supply of electricity to their customers and to ensure NSPI customers do not bear the cost of this new market.

In June 2016, the Federal government announced a formal review process for several Acts and processes including the Canadian Environmental Assessment Act ("CEAA"), the NEB processes, the Fisheries Act and the Navigation Protection Act. NSPI will participate in the consultation process.

In November 2014, the Government of Canada and the Province of Nova Scotia entered into a greenhouse gas emission regulations equivalency agreement, which allows NSPI to achieve compliance with federal greenhouse gas emissions regulations by meeting provincial legislative and regulatory requirements as they were deemed to be equivalent. In March 2016, the Prime Minister of Canada met with provincial premiers to begin the development of a pan-Canadian plan to reduce greenhouse gases. They issued a joint statement; the Vancouver Declaration, in which First Ministers agreed to work together on a pan-Canadian framework on clean growth and climate change, and implement it by early 2017. In October 2016, the Prime Minister announced that there would be a national price on carbon, implemented by 2018 through either a carbon tax or a cap and trade system, applicable in each province except those which enact their own comparable carbon pricing mechanism by that time. NSPI is providing input to the process through the Nova Scotia government, the Federal government and directly through submission of a discussion paper. The impact of the announced carbon pricing system on Emera's Canadian operating companies, and the effect, if any, on the existing equivalency agreement is uncertain at this time.

Capital expenditures for 2016, including AFUDC are forecasted to be $318 million (2015 - $274 million).

Emera Maine

Emera Maine is a transmission and distribution electric utility with assets of $1.1 billion USD, serving 158,000 customers in the State of Maine.

Emera Maine's electric revenue is comprised of distribution operations, local and regional transmission operations and stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

- Emera Maine's distribution rates are set on a 9.55 per cent ROE, with a common equity component of 49 per cent.
- For local transmission operations, the rate for the Bangor Hydro District is set on a 10.57 per cent ROE. For the Maine Public Service District, the rate is set on a 10.2 per cent ROE effective June 1 for wholesale and July 1 for retail customers. The Bangor Hydro District's bulk transmission assets are managed by ISO-New England as part of a region-wide pool of assets and have a ROE range of 11.07 per cent to 11.74 per cent. The common equity component is based upon the average balances in the prior calendar year.

- For stranded cost recoveries, the rate for the Bangor Hydro District is set on a 5.9 per cent ROE, with a common equity component of 48 per cent and for the Maine Public Service District it is set on 6.75 per cent ROE with a common equity component of 48 per cent.

Emera Maine's earnings are most directly impacted by the combined impacts of the range of rates of return on equity and rate base approved by its regulators, the prudent management and approved recovery of operating costs, load, and the timing and amount of capital expenditures. Emera Maine operates under a cost-of-service regulatory structure.

Emera Maine's 2016 ROE and earnings are expected to be generally consistent with prior years. Its ongoing investment in transmission and distribution infrastructure is expected to result in modest growth in rate base.

Emera Maine has an agreement with Central Maine Power Company to pursue specific transmission opportunities in northern Maine that would relieve transmission congestion and more efficiently collect and deliver wind to southern New England markets. As part of this agreement, Emera Maine and Central Maine Power Company jointly responded in Q1 2016 to a request for proposals from Massachusetts, Connecticut and Rhode Island. In October 2016, the companies were notified that their proposal was not selected. The companies are evaluating options and next steps for the project. The demand for new renewable energy, and the infrastructure to deliver that energy to market, is growing as a result of increasing renewable portfolio requirements of the southern New England states.

There are three pending complaints, with the FERC to challenge the ISO-New England Open Access Transmission Tariff-allowed base ROE. On March 22, 2016, the Administrative Law Judge ("ALJ") issued a recommended decision to the FERC with respect to the first two outstanding ROE complaints. The ALJ recommendation for the ENE Case was a 9.59 per cent base ROE, with a 10.42 per cent maximum ROE, and the recommendation for MA AG II Case was a 10.90 per cent base ROE, with a 12.19 per cent maximum ROE. A reserve was recognized in 2014 on a 10.57 per cent base ROE and represents Emera Maine's best estimate of the probable outcome for the two outstanding complaints. No update was made to the reserve based on the ALJ recommendation, as it is pending approval by the FERC and considered uncertain until that time. On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"), a collection of 13 municipal light departments, seeking to reduce the base ROE to 8.61 per cent and the maximum ROE to 11.24. No reserve has been made as a result of this complaint, as the outcome is considered uncertain.

In 2016, Emera Maine expects to invest approximately $65 million USD (2015 - $66 million USD actual), including approximately $33 million USD for transmission projects.

Emera Caribbean

Emera Caribbean includes the following consolidated and non-consolidated investments:

Consolidated Investments

- 100.0 per cent (December 31, 2015 – 95.5 per cent) investment in ECI and its wholly owned subsidiary BLPC, a vertically integrated utility that is the provider of electricity in Barbados. BLPC serves 126,000 customers and is regulated by the Fair Trading Commission, Barbados. BLPC's approved regulated return on rate base for 2016 is 10.0 per cent. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. On February 24, 2016, Emera completed the purchase of the remaining 4.5 per cent of common shares from minority shareholders of ECI.

- 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in GBPC, which is a vertically integrated utility and a sole provider of electricity on Grand Bahama Island. GBPC serves 19,000 customers and is regulated by the GBPA. Effective February 1, 2016, the GBPA approved GBPC's regulated return on rate base of 8.8 per cent applicable for the 2016 through 2018 period. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner.

- 51.9 per cent (December 31, 2015 – 49.6 per cent indirect controlling interest), through ECI, in Domlec, an integrated utility on the island of Dominica. Domlec serves 36,000 customers and is regulated by the IRC. Domlec's approved allowable regulated return on rate base for 2016 is 15.0 per cent. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.

Equity Investment

- 19.1 per cent (December 31, 2015 – 18.2 per cent indirect interest), through ECI, in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia. Lucelec is regulated by the National Utility Regulatory Commission (NURC) which was established in 2016 to regulate utility services in St Lucia. Lucelec was previously regulated by the Government of St Lucia. The investment in Lucelec is accounted for on the equity basis.

Earnings from Emera Caribbean are most directly impacted by the combined impacts of the range of rates of return on rate base approved by their regulators, capital structure, prudent management, approved recovery of operating costs, load, and the timing and amount of capital expenditures. Earnings are also affected by the investment returns of BLPC's self-insurance fund.

The Barbados economy is predominantly driven by tourism and is forecasted to grow modestly in 2016. However, the credit downgrades by Moody's and more recently S&P in September, of the long-term foreign and local currency sovereign ratings of Barbados, highlights the lack of market confidence that economic recovery will be sustained. The economy of Grand Bahama is highly correlated to the United States economy. In 2015, the economy of Grand Bahama exhibited signs of improving with economic growth in the industrial sector and weather related growth in the residential sector. 2016 sales are expected to be slightly lower compared to 2015 due to lower than anticipated sales in the large industrial sector.

The island of Grand Bahama took a direct hit from Hurricane Matthew in October 2016. Property damage on the island is extensive. GBPC's generation and substation infrastructure generally weathered the storm well, however over 1,500 transmission and distribution poles and related conduit were damaged or destroyed, as were many connections to customer homes. Restoration efforts are well underway, with GBPC's team being supplemented by over 200 people and over 100 pieces of equipment from other Emera affiliates, including Tampa Electric, Emera Maine, Nova Scotia Power, and Emera Utility Services. The Q3 2016 results for Emera Caribbean do not include any of the approximate $25 million USD of restoration costs which is expected to be capitalized and recovered from customers over time.

With oil being the predominant fuel source for generation of electricity in the Caribbean, and with fuel costs directly passed through electricity rates to customers, any change in global fuel prices and resulting change in fuel costs will result in a similar change in customer rates and reported revenues. GBPC has implemented fuel hedging strategies to provide increased certainty to customers as to fuel costs and electricity rates. In support of reducing carbon emissions and exposure to carbon based fuel sources, BLPC recently commissioned a 10 megawatt solar facility in Barbados, which became operational in Q2 2016. Additional renewable energy generation investments are being explored.

Overall, Emera Caribbean earnings and rate base are expected to be generally consistent with prior years, excluding the impact of the Q2 2016 gain recognized on the SIF regulatory liability. GBPC's 2016 earnings will reflect its 8.8 per cent allowable return on rate base.

In 2016, Emera Caribbean plans to invest approximately $76 million USD in capital programs in 2016 (2015 - $32 million USD actual). This increase is due to spending on a new solar facility in Barbados, as described above.

Emera Energy

Emera Energy includes the following:

- Emera Energy Services (“EES”), a wholly owned physical energy marketing and trading business.
- Emera Energy Generation (“EEG”), a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada with 1,410 megawatts (“MW”) of total capacity.
- Equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.

Wholly owned investments are consolidated. The investment in Bear Swamp is accounted for on an equity basis.

Emera Energy Services

Emera Energy Services, 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 providing the greatest opportunity for earnings.

In addition to capitalizing on volatility-driven market opportunities, Emera Energy Services expects to continue to grow organically building market share through strong customer service and expanding its geographic reach to adjacent markets, including the Marcellus Shale region.

Planned investment by the industry in gas transportation infrastructure within the northeast United States over the next few years could reduce the degree of volatility recently experienced in the market, all other things being equal. This could negatively affect profitability during certain periods.

Emera Energy Generation

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

2016 adjusted earnings from Emera Energy generating assets are expected to be lower than 2015, reflecting lower hedged and expected margins year over year.

In addition to energy margins and ancillary revenue, the NEGG Facilities and Bear Swamp earn revenue from capacity payments through the forward capacity market (“FCM”), the annual reconfiguration capacity market and the monthly reconfiguration capacity market. Prices for the FCM, the largest of the components, are determined through an auction process held annually, three years in advance, thus providing revenue visibility to 2020, presuming the facilities continue to be available to support their capacity obligations. Details of pricing and estimated revenues are outlined in the table below for the NEGG Facilities, and Emera Energy’s 50.0 per cent interest in Bear Swamp.

Forward Capacity Auction ("FCA") Year	Clearing Price in $/kW-month (in USD)	Approximate Estimated Annual Capacity Revenue (in USD) (1)
FCA6 (June 2015 to May 2016)	$3.43	$40 million
FCA7 (June 2016 to May 2017)	$3.15	$40 million
FCA8 (June 2017 to May 2018)	$7.025	$100 million
FCA9 (June 2018 to May 2019)	$9.55 and $11.08 (2)	$145 million
FCA 10 (June 2019 to May 2020)	$7.03	$106 million

(1) Includes Emera's 50 per cent share of Bear Swamp's capacity revenue.
(2) $11.08 was awarded for the Southeast Massachusetts/Rhode Island zone only and, as such, applies only to Tiverton.

Bear Swamp's adjusted earnings will be lower in 2016 and the first half of 2017 primarily due to higher interest costs as a result of its Q4 2015 refinancing. Beginning Q3 2017, these interest costs are expected to be offset by higher capacity revenues.

In 2016, Emera Energy expects to invest approximately $41 million (2015 – $42 million actual) in capital projects related to its generating assets in order to further improve reliability and increase plant 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, internal audit, 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 the following consolidated and non-consolidated investments:

Consolidated Investments

- Brunswick Pipeline is an NEB regulated, 145-kilometre pipeline that transports natural gas from Saint John, New Brunswick, to markets in the northeastern United States. The pipeline is contracted under a 25-year firm service agreement with Repsol Energy Canada that expires in 2034. The service agreement is accounted for as a direct financing lease.

- Emera Reinsurance Limited is a captive insurance company providing insurance and reinsurance to Emera and certain of its affiliates, to enable more cost efficient management of risk and deductible levels across Emera.

- Emera Utility Services is a utility services contractor primarily operating in Atlantic Canada.

- Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States.

- Emera US Finance LP, a wholly owned financing subsidiary of Emera that issued multiple series of USD denominated senior, unsecured notes.

Non-consolidated investments

- Emera’s 100 per cent investment in ENL, which holds investments in the following:

    - Emera’s 100 per cent investment in NSPML, a $1.56 billion transmission project, including two 170-kilometre subsea cables, connecting the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the return on equity component of AFUDC, which will continue until the Maritime Link Project goes into service. This project is scheduled to be completed in Q4 2017 and go into service by January 1, 2018.

    - Emera’s 62.7 per cent (December 31, 2015 - 55.1 per cent) investment in the partnership capital of LIL, a $3.4 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera’s percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera’s ultimate percentage investment in LIL will be determined upon completion and final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera’s total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in Q2 2018.

- Emera’s 12.9 per cent investment in M&NP.

- Emera’s 4.7 per cent (December 31, 2015 – 19.6 per cent) investment in APUC. APUC is a diversified generation, transmission and distribution utility traded on the Toronto Stock Exchange (“TSX”) under the symbol “AQN”. On May 24, 2016, Emera completed the sale of 50.1 million common shares of APUC, representing approximately 19.3 per cent of APUC's issued and outstanding common shares for gross proceeds of $ 544 million. On June 30, 2016, Emera exchanged 12.9 million APUC subscription receipts and dividend equivalents into 12.9 million APUC common shares. The resulting gains on the sale of the investment and conversion of subscription receipts and dividend equivalents into common shares are recorded in “Other income (expenses), net” on the Condensed Consolidated Statements of Income. APUC was accounted for on the equity basis, and Emera’s proportioned share of APUC’s earnings was included in the Condensed Consolidated Statements of Income until its sale on May 24, 2016. The common shares are now included in “Investment securities” on the Condensed Consolidated Balance Sheets, with dividend income recorded in Other income (expenses), net on the Condensed Consolidated Statements of Income.

Corporate and Other is dependent on the level of business development activity, acquisition related initiatives, which in 2016 includes costs related to the acquisition of TECO Energy, corporate financing costs, including financing of the TECO Energy transaction and other corporate activities, earnings related to Emera’s investment in APUC, AFUDC earnings as a result of equity investments in the Maritime Link Project and the Labrador-Island Link, project-based construction services activity by Emera Utility Services, and capital lease accounting treatment of the Emera Brunswick Pipeline, which yields declining earnings over the life of the asset.

Overall, Corporate and Other’s contribution to consolidated adjusted net income will be higher in 2016 primarily as the result of gains associated with the May 24, 2016 sale of a portion of Emera’s investment in APUC and the subsequent conversion of APUC subscription receipts and dividend equivalents to common shares on June 30, 2016.

Excluding the earnings impact of APUC gains described above, Corporate's contribution to consolidated adjusted net income in 2016 is expected to be lower than 2015 primarily due to acquisition costs, associated financing initiatives and interest costs related to the TECO Energy acquisition. The TECO Energy acquisition costs include a one-time non-cash accounting charge for the difference between Emera's closing share price on the issuance date of the convertible debentures and their exercise price. This charge to earnings of $43 million after tax occurred in Q3 2016 as substantially all of the convertible debentures were converted to common shares.

In 2016, Corporate and Other expects to invest approximately $11 million (2015 - $13 million actual).

ENL

NSP Maritime Link Inc. ("NSPML")

Through its subsidiary, NSP Maritime Link Inc., ENL had invested at September 30, 2016, $1.09 billion of equity, debt and working capital, including $117 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested $272 million in equity, comprised of $225 million in equity contributed and $47 million of accumulated retained earnings, with the remaining costs being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent.

ENL's future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for construction activities, which will determine the component of costs to be funded by equity. Proceeds from the federally guaranteed debt financing completed in 2014 were used to fund project costs until the Project's debt to equity ratio reached 70 per cent to 30 per cent respectively in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70 per cent to 30 per cent ratio, with equity contributions of $70 million in year-to-date in 2016.

Maritime Link Project forecasted equity contributions for 2016 and 2017 are $137 million and $150 million respectively, with total equity for the Project estimated to be $442 million.

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, currently estimated at approximately $3.4 billion. As at September 30, 2016, ENL had invested $326 million, comprised of $289 million in equity and $37 million of accumulated equity earnings in LIL. Equity earnings are recorded based on an annual rate of 8.5 per cent of the equity invested (8.8 per cent prior to July 1, 2016). The return on ROE is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB"). Future earnings are dependent on the amount and timing of additional equity investments and the approved ROE. Total equity contributions for LIL year-to-date in 2016 are $102 million.

LIL forecasted equity contributions for 2016 and 2017 are $195 million and $28 million respectively, with total equity investment, by Emera, in the Project estimated to be approximately $600 million, including $200 million of contributions forecasted subsequent to 2017.

Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Condensed Consolidated Balance Sheets.

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2015 and September 30, 2016 include:

millions of Canadian dollars	Total	Increase (Decrease) Due to Emera Florida and New Mexico	Other Increase (Decrease)	Explanation of Other Increase/Decrease
Assets				
Cash and cash equivalents	**$ (658)**	**$ 32**	**$ (690)**	Decreased primarily due to the cash paid for the acquisition of TECO Energy, partially offset by the proceeds received from the issuance of acquisition related debt and the sale of APUC common shares
Receivables, net	**241**	**351**	**(110)**	Decreased due to seasonal trends of the business in both Emera Energy and NSPI and decreased cash collateral position on derivative instruments at NSPI
Income taxes receivable, net of income taxes payable (current and long-term)	**17**	**(8)**	**25**	Increased primarily due to expected recovery of prior year income taxes at Emera Energy
Inventory	**163**	**222**	**(59)**	Decreased primarily due to lower fuel inventory volumes as a result of consumption and lower commodity pricing at NSPI
Derivative instruments (current and long-term)	**(188)**	**3**	**(191)**	Decreased primarily due to settlements of derivative instruments and strengthening of CAD dollar in both Emera Energy and NSPI
Regulatory assets (current and long-term)	**626**	**629**	**(3)**	The decrease in regulatory assets was not material
Prepaid expenses	**50**	**27**	**23**	Increased primarily due to timing of provincial grants in lieu of taxes and insurance payments at NSPI
Property, plant and equipment, net of accumulated depreciation	**10,189**	**10,222**	**(33)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and depreciation, offset by additions
Investments subject to significant influence	**(316)**	**-**	**(316)**	Decreased primarily due to the sale of APUC common shares and reclassification of the outstanding APUC common shares to investment securities, partially offset by increased investment in LIL and NSPML
Investment securities (current and long-term)	**85**	**-**	**85**	Increased primarily due to the reclassification of the outstanding APUC common shares from "Investments subject to significant influence", partially offset by the withdrawal of investments in the SIF
Goodwill	**5,757**	**-**	**5,757**	Increased due to the TECO Energy acquisition
Other assets (current and long-term)	**(128)**	**66**	**(194)**	Decreased primarily due to the amortization of transportation and storage capacity assets at Emera Energy
Liabilities and Equity				
Short-term debt and long-term debt (including current portion)	**11,403**	**5,379**	**6,024**	Increased primarily due to the issuance of long-term debt related to the TECO Energy acquisition
Accounts payable	**708**	**641**	**67**	Increased primarily due to the cash collateral position on derivative instruments at NSPI and accrued expenses related to the TECO Energy acquisition

Deferred income tax liabilities, net of deferred income tax assets	**745**	**859**	**(114)**	Decreased primarily due to additional tax losses, settlements of natural gas and power contracts at Emera Energy and the change in FAM regulatory deferral account at NSPI
Convertible debentures	**(671)**	**-**	**(671)**	Decreased due to the conversion of the convertible debentures related to the TECO Energy acquisition into common shares
Derivative instruments (current and long-term)	**(159)**	**2**	**(161)**	Decreased primarily due to settlements of natural gas and power contracts at Emera Energy, partially offset by changes in existing positions on long-term contracts
Regulatory liabilities (current and long-term)	**1,075**	**1,137**	**(62)**	Decreased primarily due to the reduction of the BLPC SIF regulatory liability and changes in regulated derivatives, partially offset by increased FAM regulatory liability at NSPI
Pension and post-retirement liabilities (current and long-term)	**419**	**426**	**(7)**	The decrease in pension and post-retirement liabilities was not material
Other liabilities (current and long-term)	**384**	**247**	**137**	Increased primarily due to the timing of the fourth quarter dividend declared at the end of Q3 in 2016 and interest on the long-term debt related to the TECO Energy acquisition
Common stock	**2,201**	**-**	**2,201**	Increased primarily due to the conversion of the convertible debentures into common shares and issuance of common stock for the dividend reinvestment program
Contributed surplus	**46**	**-**	**46**	Increased primarily due to the beneficial conversion feature discount on the convertible debentures related to the TECO Energy acquisition
Accumulated other comprehensive income	**(131)**	**24**	**(155)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and the adjustment to AOCI due to the sale of APUC common shares
Retained earnings	**(162)**	**109**	**(271)**	Decreased due to dividends paid in excess of net income
Non-controlling interest in subsidiaries	**(24)**	**-**	**(24)**	Decreased due to increased ownership by Emera in ECI

Developments

Emera

Conversion of Convertible Debentures

As at September 30, 2016, 51.9 million common shares of Emera were issued relating to the conversion of the Convertible Debentures, representing conversion into common shares of 99.5 per cent.

Increase in Common Dividend

On July 4, 2016, Emera's Board of Directors announced an increase in the annual common share dividend rate from $1.90 to $2.09. The first payment was effective August 15, 2016. Emera also extended its eight per cent annual dividend growth target from 2019 to 2020.

Acquisition of TECO Energy

On July 1, 2016, Emera acquired all of the outstanding common shares of TECO Energy for $27.55 USD per common share. The net cash purchase price totaled $8.4 billion ($6.5 billion USD), with an aggregate purchase price of $13.9 billion ($10.7 billion USD), including the assumption on closing of $5.5 billion ($4.2 billion USD) in US debt. The net cash purchase price was financed through: (i) $728 million ($560 million USD) related to the first instalment of convertible debentures represented by instalment receipts issued in 2015, $1.56 billion ($1.2 billion USD) fixed-to-floating subordinated notes, $500 million in Canadian long-term debt and $4.2 billion ($3.25 billion USD) in US long-term senior unsecured notes; (ii) available cash on hand; and (iii) drawings of $1.4 billion ($1.1 billion USD) on the Company's acquisition credit facility. Total proceeds of the debt, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

On August 2, 2016, the Convertible Debentures Final Instalment Date, Emera obtained the remaining two- thirds of the Convertible Debentures instalment. The net proceeds were $1.4 billion and were used to repay the Company's acquisition credit facility.

For further information on the acquisition of TECO Energy refer to the "Business Outlook", "Business Outlook – Emera Florida and New Mexico" and the "Emera Florida and New Mexico" segment section of this MD&A.

Registration with the United States Securities and Exchange Commission (the "SEC")

On June 1, 2016, in connection with an offering of unsecured, subordinated notes of Emera, Emera filed a preliminary short form base shelf prospectus with the Nova Scotia Securities Commission (the "NSSC") under the United States / Canada Multijurisdictional Disclosure System. On June 1, 2016, Emera also filed a corresponding shelf registration statement (the "Registration Statement") with the SEC on Form F-10.

On June 8, 2016, upon the filing of a final short form base shelf prospectus (the "Final Base Shelf Prospectus"), a receipt was obtained from the NSSC and the Registration Statement became effective on June 9, 2016. These filings provided for the offer and sale in the United States from time to time of unsecured, subordinated notes of Emera. These notes may be offered in one or more transactions, at prices, with maturities and on terms to be set forth in one or more prospectus supplements (each, a "Prospectus Supplement") to be filed with the NSSC and the SEC at the time of any such offering.

On June 10, 2016, Emera announced that it had agreed to issue and sell $1.2 billion USD aggregate principal amount of 6.75 per cent Fixed-to-Floating Subordinated Notes – Series 2016-A due June 2076 (the "Hybrid Notes"), subject to the terms and conditions of an underwriting agreement. This offering of Hybrid Notes was pursuant to a final Prospectus Supplement to the Final Base Shelf Prospectus.

On June 16, 2016, Emera announced that it had completed the sale of the Hybrid Notes. The Hybrid Notes are not currently listed and Emera does not intend to list them on any securities exchange or include them on any automated quotation system. The Hybrid Notes were not offered for sale in Canada. The final Prospectus Supplement and the accompanying Final Base Shelf Prospectus relating to the offering of the Hybrid Notes are available at www.sedar.com and www.sec.gov or may also be obtained from Emera.

Investment in APUC

On May 24, 2016, Emera completed the sale of 19.3 per cent of APUC's issued and outstanding common shares. This 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.

Proceeds of the sale were used in support of Emera's general financing requirements, including the purchase of TECO Energy. Emera also converted 12.9 million 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. After the sale and subsequent conversion, Emera holds 12.9 million outstanding APUC common shares, which are accounted for as an investment security on the Condensed Consolidated Balance Sheets. This represents a 4.7 per cent investment in APUC.

ECI Amalgamation

On February 24, 2016, the common shareholders of ECI approved an amalgamation transaction, which resulted in a wholly owned subsidiary of Emera owning all common shares of ECI. Prior to this, Emera held 95.5 per cent of ECI’s common shares.

To effect the amalgamation, all issued and outstanding common shares of ECI were converted to Class A redeemable preferred shares. In Q1 2016, the Class A redeemable preferred shares of ECI not owned were redeemed. Minority ECI shareholders could elect to receive $23.26 ($33.30 Barbadian dollars (“BBD”)) in cash per common share (“Cash Offer”) or 2.1 Depositary Receipts (“DR”) per common share, with each DR representing one quarter of a common share of Emera (“DR Offer”); or a combination of the two offers. The total consideration paid to redeem the minority interest was $15 million ($23 million BBD), consisting of $14 million of the Cash Offer ($22 million BBD) and $1 million of the DR Offer ($1 million BBD). The amalgamated entity retained the name Emera (Caribbean) Incorporated.

Recent Financing Activity

Emera – TECO Energy Acquisition Related Capital Market Transactions

U.S. Notes

On June 16, 2016, Emera US Finance LP, a limited partnership financing subsidiary, wholly owned directly and indirectly by Emera, completed the issuance of $3.25 billion USD senior unsecured notes (“U.S. Notes”). The U.S. Notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary. The U.S. notes bear interest semi-annually, in arrears, on June 15 and December 15 of each year, commencing on December 15, 2016. The U.S. notes will not be listed on a securities exchange. The U.S. notes issued are described below:

$500 million USD three year, 2.15 per cent Notes due 2019
$750 million USD five year 2.70 per cent Notes due 2021
$750 million USD ten year 3.55 per cent Notes due 2026
$1.25 billion USD thirty year 4.75 per cent Notes due 2046

Hybrid Notes

On June 16, 2016, Emera completed the issuance of $1.2 billion USD unsecured, fixed-to-floating subordinated notes (“Hybrid Notes”). The Hybrid Notes will mature on June 15, 2076. Emera will pay interest on the Hybrid Notes at a fixed rate of 6.75 per cent per year in equal semi-annual instalments on June 15 and December 15 of each year until June 15, 2026. Starting on June 15, 2026, and on every quarter thereafter that the Hybrid Notes are outstanding until their maturity on June 15, 2076 (the “Interest Reset Date”), the interest rate on the Hybrid Notes will be reset.

Beginning on June 15, 2026, and on every Interest Reset Date until June 15, 2046, the Hybrid Notes will be reset at an interest rate of the three month LIBOR plus 5.44 per cent, payable in arrears. Beginning on June 15, 2046, and on every Interest Reset Date until June 15, 2076, the Hybrid Notes will be reset at an interest rate of the three-month LIBOR plus 6.19 per cent, payable in arrears.

Emera may elect, at its sole option, to defer the interest payable on the Hybrid Notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after June 15, 2026, Emera may, at its option, redeem the Hybrid Notes, at a redemption price equal to 100 per cent of the principal amount, together with accrued and unpaid interest.

Canadian Notes

On June 16, 2016, Emera completed the issuance of $500 million senior unsecured notes ("Canadian Notes"). The Canadian Notes were issued with a seven-year term to maturity and bear interest at a rate of 2.90 per cent. The notes will bear interest semi-annually in arrears on June 16 and December 16 of each year, commencing on December 16, 2016. The Canadian Notes will not be listed on a securities exchange.

The proceeds of the U.S. Notes, Hybrid Notes and Canadian Notes offerings were used to partially finance the purchase price for the Acquisition. Proceeds of the offerings, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

As at September 30, 2016, the carrying value of the U.S., Hybrid, and Canadian Notes issued amounted to $6,261 million, and was recorded in "Long-term debt" on the Condensed Consolidated Balance Sheets.

NSPI

On April 28, 2016, NSPI increased its committed syndicated revolving bank line of credit to $600 million from $500 million. The increase will support ongoing business requirements and general corporate purposes.

On May 27, 2016, NSPI increased its commercial paper program to $500 million from $400 million, of which the full amount outstanding is backed by NSPI's operating credit facility referred to above. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

Appointments

Board of Directors

Effective September 1, 2016, John Ramil joined the Emera Board of Directors. Mr. Ramil was President and Chief Executive Officer ("CEO") of TECO Energy until his retirement on August 31, 2016.

Executive

Effective September 1, 2016, Rob Bennett, was appointed President and Chief Executive Officer of TECO Energy.

Effective September 1, 2016, in addition to his current role of Chief Financial Officer, Emera, Greg Blunden was appointed as TECO Energy's and TEC's Senior Vice President – Finance and Accounting and Chief Financial Officer (Chief Accounting Officer).

Effective September 1, 2016, Sarah MacDonald has been appointed to President of TECO Services Inc. Ms. MacDonald also leads Emera's operations in the Caribbean.

Effective August 1, 2016, Bob Hanf was appointed Executive Vice President, Stakeholder Relations and Regulatory Affairs for Emera. Most recently, he was President and CEO of NSPI.

Effective August 1, 2016, Karen Hutt was appointed President and CEO of NSPI. Previously, Ms. Hutt was Vice President, Mergers and Acquisitions, with Emera.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars	
December 31, 2014	143.78	$	2,016
Issuance of common stock	1.25		54
Issued for cash under Purchase Plans at market rate	2.10		88
Discount on shares purchased under Dividend Reinvestment Plan	-		(4)
Options exercised under senior management stock option plan	0.08		2
Employee Share Purchase Plan	-		1
December 31, 2015	147.21	$	2,157
Conversion of Convertible Debentures (2)	51.94		2,112
Issuance of common stock (1)	0.06		3
Issued for cash under Purchase Plans at market rate	1.56		72
Discount on shares purchased under Dividend Reinvestment Plan	-		(3)
Options exercised under senior management stock option plan	0.56		16
Employee Share Purchase Plan	-		1
September 30, 2016	**201.33**	**$**	**4,358**

(1) In Q1 2016, Emera issued 0.06 million common shares to facilitate the creation and issuance of 0.2 million depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange.
(2) In Q3 2016, 51.9 million common shares of Emera were issued relating to the conversion of the Convertible Debentures, representing conversion into common shares of 99.5 per cent.

As at October 24, 2016 the amount of issued and outstanding common shares was 201.39 million. The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended September 30, 2016 was 183 million (2015 – 146 million) and for the nine months ended September 30, 2016 was 161 million (2015 – 145 million).

EMERA FLORIDA AND NEW MEXICO

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Florida and New Mexico Net Income

For the millions of US dollars (except per share amounts)		Three months ended September 30 *
		2016
Operating revenues – regulated electric	$	**585**
Operating revenues – regulated gas		**147**
Operating revenues – non-regulated		**3**
Total operating revenues		**735**
Regulated fuel for generation and purchased power		**212**
Regulated cost of natural gas		**53**
Operating, maintenance and general		**159**
Provincial, state and municipal taxes		**51**
Depreciation and amortization		**92**
Total operating expenses		**567**
Income from operations		**168**
Other income (expenses), net		**8**
Interest expense, net		**44**
Income before provision for income taxes		**132**
Income tax expense (recovery)		**48**
Contribution to consolidated net income – USD	$	**84**
Contribution to consolidated net income – CAD		**109**
Contribution to consolidated earnings per common share – CAD	$	**0.68**
Net income weighted average foreign exchange rate – CAD/USD	$	**1.30**
EBITDA – USD	$	**268**
EBITDA – CAD	$	**350**

* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the “Developments” section of this MD&A.

The Emera Florida and New Mexico USD contribution to consolidated net income was $84 million in Q3 2016. This reflects results since July 1, 2016 which is the date of the acquisition by Emera.

The Emera Florida and New Mexico operating unit contribution for the three months ended September 30, 2016 is summarized in the following table:

For the millions of US dollars		Three months ended September 30*
		2016
Tampa Electric	**$**	**88**
PGS		**6**
NMGC		**(1)**
Other (1)		**(9)**
Contribution to consolidated net income	**$**	**84**

* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the “Developments” section of this MD&A.
(1) Other includes TECO Finance and administration costs.

Included below are comparisons of Emera Florida and New Mexico Q3 2016 quarterly results to the same period in 2015. Prior year data is for comparison purposes only, as the Emera acquisition was completed on July 1, 2016.

Tampa Electric's net income increased $6 million to $88 million in Q3 2016 compared to $82 million for the same period in 2015 primarily due to higher energy sales and increased AFUDC on the Polk Power Station expansion project. Higher energy sales were due to warmer weather in Q3 2016 and customer growth of 1.6 per cent.

PGS's net income of $6 million in Q3 2016 was unchanged compared to the same period in 2015 primarily due to higher sales volumes being offset by slightly higher OM&G and normal depreciation growth. PGS had increased therm sales due to 2.7 per cent customer growth and higher off-system sales to gas fired electric power generators.

NMGC's net loss decreased $2 million to $1 million in Q3 2016 compared to $3 million loss in the same period in 2015 primarily due to lower OM&G costs resulting from a focus on cost control. New Mexico's strongest quarters are Q1 and Q4 due to colder weather with Q2 and Q3 delivering lower earnings.

Other net loss of $9 million in Q3 2016 was essentially unchanged for the same period in 2015, excluding costs related to TECO Energy's former coal mining operations subsidiary, TECO Coal LLC, which was sold on September 21, 2015.

The Emera Florida and New Mexico CAD dollar contribution to consolidated net income was $109 million in Q3 2016.

Operating Revenues – Regulated

Emera Florida and New Mexico's operating revenues - regulated include sales of electricity, gas and other services as summarized in the following table:

Q3 Operating Revenues – Regulated*
millions of US dollars

		2016
Electric revenues - regulated (1)	**$**	**585**
Gas revenues - regulated (1)		**147**
Operating revenues – regulated	**$**	**732**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Electric and gas regulated revenues include regulatory deferrals related to over-recovery of fuel and clause related costs, if any. Under recoveries are included in the related expense

Electric and Gas Revenues

Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Residential and commercial electricity and gas sales are seasonal. In Florida, Q3 is the strongest period for electricity sales, reflecting warmer weather and cooling demand. In New Mexico and Florida, Q1 is the strongest period for gas sales due to colder weather and heating demand.

Emera Florida and New Mexico's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. The gas utilities' industrial customers include manufacturing facilities and other large volume operations. Other sales volumes consist primarily of off-system sales to other utilities and revenues from street lighting.

Q3 Electric Sales Volumes
GWh

	2016	2015*	2014*
Residential	**2,960**	2,729	2,779
Commercial	**1,814**	1,754	1,773
Industrial	**499**	444	483
Other	**503**	474	494
Total	**5,776**	5,401	5,529

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Q3 Gas Sales Volumes
Therms (millions)

	2016	2015*	2014*
Residential	**35**	34	35
Commercial	**150**	146	142
Industrial (1)	**328**	303	293
Other	**91**	55	44
Total	**604**	538	514

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

(1) Industrial gas sales include on-system power generation customers.

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

Q3 Electric Revenues*
millions of US dollars

		2016
Residential	**$**	**331**
Commercial		**167**
Industrial		**42**
Other (1)		**45**
Total	**$**	**585**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the “Developments” section of this MD&A.
(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

Electric revenues increased $25 million to $585 million in Q3 2016 compared to $560 million in Q3 2015 primarily due to higher sales volumes from warmer weather and customer growth.

Q3 Gas Revenues*
millions of US dollars

		2016
Residential	**$**	**56**
Commercial		**42**
Industrial		**6**
Other (1)		**43**
Total	**$**	**147**

*Financial results of TECO Energy are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the “Developments” section of this MD&A.
(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

Gas revenues increased $15 million to $147 million in Q3 2016 compared to $132 million in Q3 2015 primarily due to an increase in off-system sales in Florida resulting from greater power generation demand from warmer weather and coal-to-gas switching due to relative pricing of each.

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

Electric Capacity

Tampa Electric is required to maintain a generation capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is 4,730 MW, which is supplemented by 488 MW contracted with other regulated utilities and independent power producers in Florida. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20% reserve margin over firm peak demand.

Tampa Electric is investing in 460 MW of additional capacity at the Polk Power Station. The expansion is expected to be completed in January 2017.

Q3 Production Volumes
GWh

	2016	2015*	2014*
Natural gas (1)	**2,494**	3,073	2,223
Coal and petroleum coke ("petcoke") (2)	**2,705**	2,249	3,251
Purchased power	**846**	377	246
Total production volumes	**6,045**	5,699	5,720

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.
(1) Natural gas production volumes in 2016 are lower due to outages related to the Polk conversion project.
(2) Includes production from the Big Bend coal units and Polk 1 IGCC unit that burns an 80/20 blend of coal and petcoke.

Q3 Average Fuel Costs/MWh*

US dollars		2016
Dollars per MWh	$	35

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the “Developments” section of this MD&A.

Average fuel cost per MWh was $35 in 2016 compared to $36 in 2015 and $39 in 2014. The reduction in fuel cost is primarily due to lower natural gas pricing.

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

Historically, coal and petcoke have the lowest per unit fuel cost, with natural gas being the next lowest. However, recent declines in natural gas prices and better overall thermal efficiencies have at times resulted in natural gas generation dispatching before coal and petcoke units.

Regulated fuel for generation and purchased power increased $10 million to $212 million in Q3 2016 compared to $202 million in Q3 2015 primarily due to higher sales volumes and an increase in purchased power to cover outages related to the Polk Power Station expansion project. This was partially offset by lower natural gas prices.

Cost of Natural Gas

Emera Florida and New Mexico gas utilities, PGS and NMGC, purchase gas from various suppliers depending on the needs of its customers. In Florida, the gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers. NMGC's service territory is situated between two large natural gas production basins (the San Juan Basin to the northwest of NMGC's service territory and the Permian Basin to the southeast of NMGC's service territory). Natural gas is transported from these production basins on major interstate pipelines to NMGC's intrastate transmission system and then to customers using its distribution system.

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually and elect this option, affording these customers the opportunity to purchase gas from any provider. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net earnings affect when a customer shifts to transportation-only sales.

Gas sales by type are summarized in the following table:

Q3 Gas Sales Volumes by Type

Therms (millions)	**2016**	2015*	2014*
System Supply	**131**	95	86
Transportation	**473**	443	428
Total	**604**	538	514

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Gas sales volumes in Q3 2016 are higher than Q3 2015 primarily due to the increase in off-system sales in Florida, which are low gas margin per therm sales.

Regulatory Recovery Mechanisms

Tampa Electric

Fuel Recovery Clause
Tampa Electric has a fuel recovery clause that is approved by the FPSC, allowing it the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Other Cost Recovery Clauses
The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs including a return on capital invested. Differences between the prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred to a corresponding regulatory asset or liability and recovered from or returned to customers in a subsequent year. In November 2015, the FPSC approved the 2016 cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs.

PGS

Fuel Recovery Clause
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment ("PGA") clause. This clause is designed to recover the actual costs incurred by PGS for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

Other Cost Recovery Clauses
The FPSC annually approves cost-recovery rates for conservation costs including a return on capital invested incurred in developing and implementing energy conservation programs. In 2012, the FPSC approved a new Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. The FPSC approved a replacement program of approximately 5 per cent, or 800 kilometers, of the PGS system at a cost of approximately $80 million over a 10-year period.

NMGC

Fuel Recovery Clause
NMGC recovers gas supply costs through a purchased gas adjustment clause ("PGAC"). This clause recovers NMGC's actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers.

On a monthly basis, NMGC can adjust the charges based on next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC's annual PGAC period runs from September 1 to August 31 and the reconciliation is filed in December. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. NMGC filed its last PGAC Continuation Filing in June 2016 for the four-year period ending December 2020. A decision is expected in Q4 2016.

Electric and Gas Revenue Margin

Emera Florida and New Mexico's utilities distinguish revenues related to various regulated clauses from revenues related primarily to the recovery of non-fuel costs ("base rates"). Electric and gas margin ("margin") and net income are derived primarily by base rates and the return on Florida utility assets associated with regulator approved cost recovery clauses. Fuel and other non-fuel cost recovery clauses do not have a material effect on margin, as substantially all costs are recovered from customers but do include a return on capital invested related to these clauses.

Customer classes contribute differently to base rate revenue, with residential and commercial customers contributing more on a dollar basis than industrial customers. Residential and commercial load is primarily affected by changes in weather and economic conditions, while industrial load is primarily affected by economic conditions.

Regulated operating revenues are shown separately by those recovered through base rates and those recovered by various fuel and non-fuel recovery clauses and are outlined below for the three months ended September 30, 2016:

For the millions of US dollars			Three months ended September 30 *
	Electric	**Gas**	**Total**
Electric and gas revenues – base rate	$ 299	$ 78	$ 377
Fuel electric and gas revenues (1)	215	55	270
Other non-fuel cost recovery clause revenues (1)	30	5	35
Other operating revenues	13	4	17
Gross receipts tax and franchise fees revenues (2)	28	5	33
Regulated operating revenues	$ 585	$ 147	$ 732

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance.

(2) Gross receipts and franchise fees for Tampa Electric and PGS are collected from customers on a dollar-for-dollar basis. As a result, they are included in "Regulated revenues and as an offsetting expense in "Provincial, state and municipal taxes" on the Condensed Consolidated Statements of Income.

Electric margin for the three months ended September 30, 2016 is summarized in the following table:

For the millions of US dollars	Three months ended September 30*
	2016
Electric base rate revenue	**$ 299**
Other electric non-fuel cost recovery clause revenues	**30**
Other electric non-fuel clause costs, net of deferrals	**(21)**
Electric fuel clause revenue	**215**
Electric fuel clause costs, net of deferrals	**(214)**
Electric margin	**$ 309**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

Emera Florida and New Mexico's electric margin increased $16 million to $309 million in Q3 2016 compared to $293 million in Q3 2015 primarily due to increased sales volumes reflecting warmer weather and customer growth.

Gas margin for the three months ended September 30, 2016 are summarized in the following table:

For the millions of US dollars	Three months ended September*
	2016
Gas base rate revenue	**$ 78**
Other gas non-fuel cost recovery clause revenues	**5**
Other gas clause recoverable costs, net of deferrals	**(4)**
Gas fuel clause revenue	**55**
Gas fuel clause cost, net of deferrals	**(54)**
Gas margin	**$ 80**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

Emera Florida and New Mexico's gas margin increased $3 million to $80 million in Q3 2016 compared to $77 million in Q3 2015 primarily due to increased sales volumes due to customer growth and additional capital investments earning returns through the PGS Cast Iron/Bare Steel Pipe Replacement clause.

Income Taxes

The Florida utilities are subject to corporate income tax at the statutory rate of 38.6 per cent (combined US federal and Florida state income tax rate). NMGC is subject to corporate income tax at the statutory rate of 39.0 per cent (combined US federal and New Mexico state income tax rate). Emera Florida and New Mexico's effective tax rate for the three months ended September 30, 2016 was 36.4 per cent, which was lower than the statutory rates primarily due to AFUDC-equity at Tampa Electric.

Non-GAAP Measure

Electric and Gas Margin Reconciliation

"Electric and gas margin" is a non-GAAP financial measure used to show the amounts that Tampa Electric, PGS and NMGC retain to recover their non-clause recoverable costs. Effectively, all prudently incurred clause recoverable costs are recovered through the fuel clauses or various other regulatory clause mechanisms approved by the FPSC and NMPRC. Electric and gas margin associated with non-fuel recovery clauses are essentially the return on assets employed, as all other costs are fully recovered.

The companies' electric and gas margin may not be comparable to other companies' electric or gas margin measures, but in management's view appropriately reflects the utilities' regulatory framework. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric and gas margin was discussed in the Financial Review Electric and Gas Margin section above.

For the millions of US dollars		Electric Margin		Gas Margin		Three months ended September 30 2016* Total
Income from operations	**$**	154	$	14	$	**168**
Less:						
Operating revenues – non-regulated		-		3		**3**
Fuel electric and gas revenues		215		55		**270**
Other clause revenues		30		5		**35**
Other operating revenues		13		4		**17**
Gross receipts tax and franchise fees revenues		28		5		**33**
Add back:						
Regulated fuel for generation and purchased power		212		-		**212**
Cost of natural gas sold		-		53		**53**
Operating, maintenance and general –non-clause related		111		48		**159**
Provincial, state and municipal taxes		41		10		**51**
Depreciation and amortization – non-clause related		67		25		**92**
Non-base rate margin contribution (1)		10		2		**12**
Electric and gas margin	**$**	309	$	80	$	**389**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance – see electric and gas margin discussion above for details of the contributions.

NSPI

Review of 2016

NSPI Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Operating revenues – regulated electric	**$ 292**	$ 305	**$ 1,004**	$ 1,079
Regulated fuel for generation and purchased power (1)	**112**	110	**354**	410
Regulated fuel adjustment mechanism and fixed cost deferrals	**6**	16	**48**	31
Operating, maintenance and general	**68**	76	**223**	232
Provincial grants and taxes	**9**	10	**29**	29
Depreciation and amortization	**51**	52	**148**	154
Total operating expenses	**246**	264	**802**	856
Income from operations	**46**	41	**202**	223
Other expenses, net	**1**	2	**3**	6
Interest expense, net	**31**	31	**93**	91
Income before provision for income taxes	**14**	8	**106**	126
Income tax expense (recovery)	**(1)**	1	**10**	30
Net income of Nova Scotia Power Inc.	**15**	7	**96**	96
Preferred stock dividends	**-**	2	**-**	6
Contribution to consolidated net income	**$ 15**	$ 5	**$ 96**	$ 90
Contribution to consolidated earnings per common share	**$ 0.08**	$ 0.03	**$ 0.60**	$ 0.62
EBITDA	**$ 96**	$ 91	**$ 347**	$ 371

(1) Regulated fuel for generation and purchased power includes affiliate transactions and proceeds from the sale of natural gas.

NSPI's contribution to consolidated net income increased $10 million to $15 million in Q3 2016 compared to $5 million in Q3 2015. Year-to-date, NSPI's contribution to consolidated net income increased $6 million to $96 million in 2016 compared to $90 million in 2015.

Highlights of the 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 – 2015	**$ 5**	**$ 90**
Decreased electric margin (see Electric Margin section below for explanation)	(2)	(23)
Decreased fixed cost deferrals primarily due to 2015 demand side management ("DSM") regulatory deferral, partially offset by a reduction in the amount of non-fuel revenues deferred	-	(8)
Decreased operating, maintenance and general ("OM&G") expenses primarily due to timing for planned maintenance, a change in mode of operation of a coal plant and lower pension expense. Year-over-year is partially offset by higher storm costs	6	2
Decreased DSM program costs	2	7
Decreased income tax expense primarily due to a legislated change by the Province of Nova Scotia to the deferred tax treatment of the South Canoe and Sable wind farms in Q4 2015 resulting in deferred income taxes being recorded as regulatory assets rather than through earnings and increased accelerated tax deductions related to property, plant and equipment. Year-over-year decrease also due to decreased income before provision for income taxes	2	20
Other	2	8
Contribution to consolidated net income – 2016	**$ 15**	**$ 96**

Operating Revenues – Regulated Electric

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Electric revenues	**$ 284**	$ 296	**$ 984**	$ 1,056
Other revenues	**8**	9	**20**	23
Operating revenues – regulated electric	**$ 292**	$ 305	**$ 1,004**	$ 1,079

Electric Revenues

NSPI's electric revenue is affected by rates approved by the UARB and electric sales volumes.

Electric sales volume is primarily driven by general economic conditions, population, weather and DSM activities. Residential and commercial electricity sales are seasonal, with Q1 being the strongest period, reflecting colder weather and fewer daylight hours in the winter season.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric revenues consist primarily of sales to municipal electric utilities and revenues from street lighting.

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

Q3 Electric Sales Volumes
Gigawatt hours ("GWh")

	2016	2015	2014
Residential	**777**	800	787
Commercial	**729**	733	723
Industrial	**645**	663	657
Other	**69**	70	70
Total	**2,220**	2,266	2,237

YTD Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**3,175**	3,409	3,287
Commercial	**2,298**	2,377	2,325
Industrial	**1,813**	1,865	1,883
Other	**213**	255	237
Total	**7,499**	7,906	7,732

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

Q3 Electric Revenues
millions of Canadian dollars

	2016	2015	2014
Residential	**$ 129**	$ 134	$ 126
Commercial	**94**	95	90
Industrial	**50**	56	54
Other	**11**	11	12
Total	**$ 284**	$ 296	$ 282

YTD Electric Revenues
millions of Canadian dollars

	2016	2015	2014
Residential	**$ 508**	$ 545	$ 504
Commercial	**298**	310	290
Industrial	**146**	163	164
Other	**32**	38	37
Total	**$ 984**	$ 1,056	$ 995

Electric revenues decreased $12 million to $284 million in Q3 2016 compared to $296 million in Q3 2015. Year-to-date, electric revenues decreased $72 million to $984 million in 2016 from $1,056 million in 2015. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Electric revenues – 2015	**$**	**296**	**$**	**1,056**
Decreased fuel related electricity pricing effective January 1, 2016		(3)		(9)
Decreased residential sales volume, in part due to weather in Q1		(3)		(32)
Decreased commercial sales volume		-		(8)
Decreased industrial sales volume		(6)		(18)
Other		-		(5)
Electric revenues – 2016	**$**	**284**	**$**	**984**

Regulated Fuel for Generation and Purchased Power

Q3 Production Volumes
GWh

	2016	2015	2014
Coal	**1,121**	1,087	831
Natural gas	**378**	336	670
Oil and petcoke	**253**	304	273
Purchased power – other	**112**	110	133
Total non-renewables	**1,864**	1,837	1,907
Wind and hydro – renewables	**133**	260	188
Purchased power – Independent Power Producers ("IPP")	**219**	199	163
Purchased power – Community Feed-in Tariff ("COMFIT")	**94**	59	5
Biomass – renewables	**56**	36	95
Total renewables	**502**	554	451
Total production volumes	**2,366**	2,391	2,358

YTD Production Volumes
GWh

	2016	2015	2014
Coal	**3,430**	3,683	3,822
Natural gas	**963**	948	1,282
Oil and petcoke	**1,108**	1,404	1,154
Purchased power – other	**301**	307	227
Total non-renewables	**5,802**	6,342	6,485
Wind and hydro – renewables	**851**	1,047	966
Purchased power – IPP	**833**	679	582
Purchased power – COMFIT	**304**	176	12
Biomass – renewables	**162**	143	196
Total renewables	**2,150**	2,045	1,756
Total production volumes	**7,952**	8,387	8,241

Q3 Average Fuel Costs

		2016		2015		2014
Dollars per MWh produced	**$**	**47**	$	46	$	44

YTD Average Fuel Costs

		2016		2015		2014
Dollars per MWh produced	**$**	**44**	$	49	$	47

Average unit fuel costs for Q3 2016 increased as a result of decreased hydro and wind production, partially offset by favourable changes in commodity pricing. Average unit fuel costs year-to-date decreased primarily due to lower commodity pricing and reduced load requiring less generation to be sourced from higher cost alternatives.

NSPI's Fuel Costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first (after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place), such that the incremental cost of production generally increases as sales volumes increase. Generation mix may also be affected by plant outages, availability of renewable generation, plant performance and compliance with environmental standards and regulations.

NSPI owned regulated hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, with natural gas being the next lowest. However, recent declines in natural gas prices and better overall thermal efficiencies have at times resulted in natural gas dispatching before petcoke and coal units. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix is transforming with the addition of new non-dispatchable renewable energy sources such as wind, including IPP and COMFIT, which typically has a higher cost per MWh.

Regulated fuel for generation and purchased power increased $2 million to $112 million in Q3 2016 compared to $110 million in Q3 2015. Year-to-date, regulated fuel for generation and purchased power decreased $56 million to $354 million in 2016 compared to $410 million during the same period in 2015. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Regulated fuel for generation and purchased power – 2015	**$ 110**	**$ 410**
Decreased commodity prices	(3)	(48)
Decreased sales volumes	(1)	(22)
Change in generation mix	(1)	6
Decreased hydro and wind production	6	9
Other	1	(1)
Regulated fuel for generation and purchased power – 2016	**$ 112**	**$ 354**

Regulated Fuel Adjustment Mechanism ("FAM") and Fixed Cost Deferrals

Regulated Fuel Adjustment Mechanism and FAM Regulatory Deferral

NSPI has a Fuel Adjustment Mechanism which enables it to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

The FAM is subject to an incentive with NSPI retaining or absorbing 10 per cent of the over or under-recovered Fuel Cost amount to a maximum of $5 million. The incentive was suspended for 2012 through 2015 as a result of UARB approved settlement agreements and is in effect for 2016. The incentive is suspended as part of the *Electricity Plan Act* in 2017 to 2019.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. The last audit completed was for 2012 and 2013. On August 12, 2016, the FAM audit results relating to fiscal 2014 and 2015 were publicly released and recommended one disallowance in the amount of approximately $1 million. NSPI has issued its response to the audit report and disagrees with the recommended disallowance and a number of other findings in the report. A UARB regulatory process is in progress with a hearing scheduled for December 2016.

In December 2015, the UARB approved NSPI's 2016 fuel rates and its recovery of prior period unrecovered Fuel Costs as submitted in the Company's filings. Approved customer rates reset the base cost of fuel rate for 2016 and seeks to recover $13 million of prior years' unrecovered Fuel Costs in 2016. Recovery of these costs began January 1, 2016.

On December 18, 2015, the *Electricity Plan Act* was enacted by the Province of Nova Scotia. In accordance with the *Electricity Plan* Act, on March 7, 2016, NSPI filed with the UARB a three-year stability plan for Fuel Costs. On July 19, 2016 the UARB approved a consensus agreement between NSPI and customer representatives which resulted in an average annual increase of 1.1 per cent for 2017 through 2019. Subsequently, certain customer representatives requested changes to certain classes of rates based on new information. If the rates requested by the customer representatives are approved by the UARB, the average annual rate increase of 1.1 per cent in the Consensus Agreement would increase to a 1.5 per cent average increase for each of these three years. A decision on the compliance filing is expected from the UARB in the fourth quarter of 2016.

The *Electricity Plan* Act directed that differences between actual Fuel Costs and amounts recovered from customers during 2016 are to be deferred to a FAM regulatory asset or liability and will be recovered from or returned to customers in the 2017 to 2019 period. In addition it stated that differences between actual Fuel Costs and amounts recovered from customers through electricity rates during 2017 through 2019 will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers after 2019.

The *Electricity Plan Act* further directed NSPI to apply any non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. Further, any non-fuel revenues in excess of NSPI's approved range of return in 2017 through 2019 will be reserved and applied subsequent to 2019. In addition the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable wind projects is to be reserved and applied to the FAM to be used in the 2017 to 2019 period. The exception to this direction was the application of $4 million of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016.

For the three months ended September 30, 2016, NSPI applied $4 million (year-to-date $12 million) of non-fuel revenues to the FAM for the periods 2017 through 2019. This was as a result of applying the tax benefits associated with the South Canoe and Sable wind projects as directed by the *Electricity Plan Act*.

The impact of the FAM included in the Statements of Income include the effect of Fuel Costs in both the current and preceding years and are detailed below:

- The difference between actual Fuel Costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities" on the Balance Sheets; and
- The recovery from (rebate to) customers of under (over) recovered Fuel Costs from prior years.

The FAM regulatory asset (liability) includes amounts recognized as a fuel adjustment mechanism and associated interest that is included in "Interest expense, net" on the Statements of Income. Details of the FAM regulatory asset (liability), classified in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets, are summarized in the following table:

millions of Canadian dollars		**2016**
FAM regulatory liability – Balance as at January 1	**$**	**(28)**
Over recovery of current period Fuel Costs		(27)
Recovery from customers of prior years' Fuel Costs		(9)
Interest on FAM balance		(4)
Application of non-fuel revenues primarily associated with tax benefits		(12)
FAM regulatory liability – Balance as at September 30	**$**	**(80)**

Electric Revenue and Margin

NSPI distinguishes electric revenues related to the recovery of Fuel Costs ("fuel electric revenues") from revenues related to the recovery of non-fuel costs ("non-fuel electric revenues") because the FAM effectively seeks to recover all prudently incurred Fuel Costs, and consequently, Fuel Costs and fuel electric revenues do not have a material effect on NSPI's electric margin or net income with the exception of the incentive component of the FAM. The incentive component is where NSPI retains or absorbs 10 per cent of the over or under recovered amount to a maximum of $5 million.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to the Company's non-fuel electric revenues, with residential and commercial customers contributing more than industrial customers under current rates. Accordingly, changes in residential and commercial load, largely due to the effects of weather, from general economic conditions and from DSM have the largest effect on non-fuel electric revenues and electric margin. Changes in industrial load, which are generally due to economic conditions and DSM, have less of an effect on non-fuel electric revenues than would a similar volume change in residential and commercial load.

The addition of new generation sources to meet legislated greenhouse gas emission reductions and renewable generation requirements is among the drivers increasing NSPI's fixed costs.

Operating revenues are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Fuel electric revenues – current year	**$ 113**	$ 112	**$ 383**	$ 396
Fuel electric revenues – recovery of preceding years	**2**	11	**9**	42
Non-fuel electric revenues	**169**	173	**592**	618
Other revenues	**8**	9	**20**	23
Operating revenues	**$ 292**	$ 305	**$ 1,004**	$ 1,079

Electric margin is summarized in the following table:

Fuel electric revenues – current year	**$ 113**	$ 112	**$ 383**	$ 396
Fuel electric revenues – recovery of preceding years	**2**	11	**9**	42
Total fuel electric revenues	**115**	123	**392**	438
Regulated fuel for generation and purchased power	**(112)**	(110)	**(354)**	(410)
Regulated fuel adjustment mechanism	**(2)**	(12)	**(36)**	(27)
Fuel-related foreign exchange gain (loss) (1)	**1**	(1)	**1**	(1)
Net fuel revenue (expense) (2)	**2**	-	**3**	-
Non-fuel electric revenues	**169**	173	**592**	618
Electric margin	**$ 171**	$ 173	**$ 595**	$ 618

(1) As reported in "Other expenses, net" on the Statements of Income.
(2) The net fuel revenue is primarily a result of the FAM incentive.

NSPI's electric margin decreased $2 million to $171 million in Q3 2016 compared to $173 million in Q3 2015 and year-to-date decreased $23 million to $595 million in 2016 compared to $618 million in 2015. The year-to-date variance is primarily due to decreased residential and commercial sales reflecting warmer weather in Q1 2016 and decreased load.

Q3 Average Electric Margin/MWh

	2016	2015	2014
Dollars per MWh sold	**$ 77**	$ 76	$ 77

YTD Average Electric Margin/MWh

	2016	2015	2014
Dollars per MWh sold	**$ 79**	$ 78	$ 78

NSPI's electric margin per MWh is consistent period over period.

Non-GAAP Measure

Electric Margin Reconciliation

“Electric margin” is a non-GAAP financial measure used to show the amounts that NSPI retains to recover its non-fuel costs, as effectively all prudently incurred Fuel Costs are recovered through the FAM. NSPI’s electric margin may not be comparable to other companies’ electric margin measures, but in management’s view appropriately reflects NSPI’s regulatory framework. This measure is not intended to replace “Income from operations” which, as determined in accordance with USGAAP, is an indicator of operating performance. Electric margin was discussed in the Financial Review Electric Margin section above.

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Income from operations	**$ 46**	$ 41	**$ 202**	$ 223
Less:				
Fuel electric revenues	**115**	123	**392**	438
Other revenues	**8**	9	**20**	23
Add back:				
Regulated fuel for generation and purchased power	**112**	110	**354**	410
Operating, maintenance and general	**68**	76	**223**	232
Provincial grants and taxes	**9**	10	**29**	29
Depreciation and amortization	**51**	52	**148**	154
Regulated fuel adjustment and fixed cost deferrals	**6**	16	**48**	31
Other fuel related costs	**2**	-	**3**	-
Electric margin	$ **171**	**$** 173	**$ 595**	**$** 618

EMERA MAINE

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Maine Net Income

For the millions of US dollars (except per share amounts)		Three months ended September 30			Nine months ended September 30	
		2016		2015	**2016**	2015
Operating revenues – regulated electric	**$**	**59**	$	59 **$**	**168**	$ 169
Operating revenues – non-regulated		**-**		1	**-**	1
Total operating revenues		**59**		60	**168**	170
Regulated fuel for generation and purchased power		**7**		9	**22**	22
Transmission pool expense (1)		**8**		7	**20**	19
Operating, maintenance and general		**11**		12	**39**	35
Provincial, state and municipal taxes		**3**		3	**10**	10
Depreciation and amortization		**7**		8	**27**	27
Total operating expenses		**36**		39	**118**	113
Income from operations		**23**		21	**50**	57
Other income (expenses), net		**1**		1	**2**	3
Interest expense, net		**4**		4	**11**	10
Income before provision for income taxes		**20**		18	**41**	50
Income tax expense (recovery)		**7**		7	**14**	18
Contribution to consolidated net income – USD	**$**	**13**	$	11 **$**	**27**	$ 32
Contribution to consolidated net income – CAD	**$**	**17**	$	15 **$**	**36**	$ 40
Contribution to consolidated earnings per common share – CAD	**$**	**0.09**	$	0.10 **$**	**0.22**	$ 0.28
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.30**	$	1.31 **$**	**1.32**	$ 1.26
EBITDA – USD	**$**	**31**	$	30 **$**	**79**	$ 87
EBITDA – CAD	**$**	**39**	$	39 **$**	**104**	$ 109

(1) Transmission pool expense is included in “Regulated fuel for generation and purchased power” on the Condensed Consolidated Statements of Income.

Emera Maine’s USD contribution to consolidated net income increased by $2 million to $13 million in Q3 2016 compared to $11 million in Q3 2015. Year-to-date, Emera Maine’s USD contribution to consolidated net income decreased by $5 million to $27 million in 2016 compared to $32 million during the same period in 2015. Highlights of the USD 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 – 2015	**$**	**11**	**$**	**32**
Decreased operating revenues - regulated electric year-over-year (see Operating Revenues - Regulated Electric Section below)		-		(1)
Increased OM&G year-over-year due to decreased capitalized construction overheads as a result of lower capital spending and increased storm costs		1		(4)
Decreased income tax expense year-over-year primarily due to decreased income before provision for income taxes		-		4
Other		1		(4)
Contribution to consolidated net income – 2016	**$**	**13**	**$**	**27**

Emera Maine’s CAD contribution to consolidated net income increased by $2 million to $17 million in Q3 2016 from $15 million in Q3 2015 and year-to-date decreased by $4 million to $36 million in 2016 from $40 million during the same period in 2015. The foreign exchange rate had no impact for the three months ended September 30, 2016. The impact of a stronger USD increased CAD earnings by $2 million for the nine months ended September 30, 2016.

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

	2016	2015
Electric revenues	**$ 41**	$ 42
Transmission pool revenues	**16**	15
Resale of purchased power	**2**	2
Operating revenues – regulated electric	**$ 59**	$ 59

YTD Operating Revenues – Regulated Electric
millions of US dollars

	2016	2015
Electric revenues	**$ 120**	$ 122
Transmission pool revenues	**39**	38
Resale of purchased power	**9**	9
Operating revenues – regulated electric	**$ 168**	$ 169

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Electric sales pricing in Maine is regulated, and therefore can change in accordance with regulatory decisions.

Q3 Electric Sales Volumes

GWh	**2016**	2015	2014
Residential	**194**	191	192
Commercial	**203**	204	206
Industrial	**101**	121	113
Other	**3**	4	4
Total	**501**	520	515

YTD Electric Sales Volumes

GWh	**2016**	2015	2014
Residential	**588**	603	602
Commercial	**584**	585	595
Industrial	**267**	333	322
Other	**11**	11	11
Total	**1,450**	1,532	1,530

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

Q3 Electric Revenues
millions of US dollars

	2016	2015	2014
Residential	**$ 19**	$ 19	$ 19
Commercial	**16**	15	14
Industrial	**4**	5	4
Other (1)	**2**	3	2
Total	**$ 41**	$ 42	$ 39

YTD Electric Revenues
millions of US dollars

	2016	2015	2014
Residential	**$ 57**	$ 57	$ 56
Commercial	**45**	43	43
Industrial	**10**	11	12
Other (1)	**8**	11	5
Total	**$ 120**	$ 122	$ 116

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

Electric revenues decreased $1 million to $41 million in Q3 2016 compared to $42 million in Q3 2015. Year-to-date, electric revenues decreased $2 million to $120 million in 2016 compared to $122 million during the same period in 2015. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Electric revenues – 2015	**$**	**42**	**$**	**122**
Decreased sales volumes primarily due to loss of load associated with the closing of two large industrial customers in December 2015, year-over-year decrease also due to the impact of weather		(1)		(6)
Increased primarily due to rate changes		1		7
Increased due to changes in FERC transmission rate refund reserves		-		1
Decreased due to changes in transmission revenue adjustments		(1)		(4)
Electric revenues – 2016	**$**	**41**	**$**	**120**

Q3 Average Electric Revenue / MWh						
US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**82**	$	81	$	76

YTD Average Electric Revenue / MWh						
US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**83**	$	80	$	76

The increase in the average electric revenue per MWh in Q3 2016 compared to Q3 2015 reflects increased transmission rates offset by transmission revenue adjustments and reduced sales volume. The year-to-date increase in average electric revenue per MWh in 2016 compared to the same period in 2015 reflects increased transmission rates and changes in the amounts recorded related to the transmission rate refund associated with the FERC ROE complaints, partially offset by transmission revenue adjustments.

Transmission Pool Revenues and Expenses

Transmission pool revenues are recorded in “Operating revenues – regulated electric” and transmission pool expenses are recorded in “Regulated fuel for generation and purchased power” in the Condensed Consolidated Statements of Income.

Transmission pool revenues and expenses are summarized in the following table:

For the millions of US dollars		Three months ended September 30				Nine months ended September 30		
		2016		2015		**2016**		2015
Transmission pool revenues	**$**	**16**	$	15	**$**	**39**	$	38
Transmission pool expenses		**8**		7		**20**		19
Net transmission pool revenues	**$**	**8**	$	8	**$**	**19**	$	19

Emera Maine’s net transmission pool revenues were flat compared to 2015 for both the quarter and year-to-date.

EMERA CARIBBEAN

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Caribbean Net Income

For the millions of US dollars (except per share amounts)		Three months ended September 30				Nine months ended September 30
		2016		2015		**2016**		2015
Operating revenues – regulated electric	**$**	**89**	$	92	**$**	**238**	$	262
Operating revenues – non-regulated		**-**		2		**-**		6
Total operating revenues		**89**		94		**238**		268
Regulated fuel for generation and purchased power		**37**		42		**94**		121
Non-regulated direct costs		**-**		2		**-**		6
Operating, maintenance and general		**20**		24		**65**		78
Property taxes (1)		**1**		-		**2**		1
Depreciation and amortization		**9**		9		**28**		26
Total operating expenses		**67**		77		**189**		232
Income from operations		**22**		17		**49**		36
Income from equity investment		**1**		1		**2**		1
Other income (expenses), net		**4**		1		**46**		3
Interest expense, net		**3**		3		**8**		8
Income before provision for income taxes		**24**		16		**89**		32
Income tax expense (recovery)		**1**		1		**10**		1
Net income		**23**		15		**79**		31
Non-controlling interest in subsidiaries		**2**		3		**5**		7
Preferred stock dividends (2)		**2**		1		**3**		3
Contribution to consolidated net income – USD	**$**	**19**	$	11	**$**	**71**	$	21
Contribution to consolidated net income – CAD	**$**	**24**	$	13	**$**	**92**	$	27
Contribution to consolidated earnings per common share – CAD	**$**	**0.13**	$	0.09	**$**	**0.57**	$	0.19
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.31**	$	1.31	**$**	**1.30**	$	1.27
EBITDA – USD	**$**	**36**	$	28	**$**	**125**	$	66
EBITDA – CAD	**$**	**46**	$	36	**$**	**164**	$	84

(1) Included in "Provincial, state and municipal taxes" on the Condensed Consolidated Statements of Income.

(2) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Condensed Consolidated Statements of Income.

Emera Caribbean's USD contribution to consolidated net income increased by $8 million to $19 million in Q3 2016 compared to $11 million in Q3 2015. Year-to-date, Emera Caribbean's USD contribution to consolidated net income increased by $50 million to $71 million in 2016 compared to $21 million during the same period in 2015. 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 – 2015	**$**	**11**	$	**21**
Increased Electric Margin – see Electric Margin section		2		3
Decreased OM&G primarily due to operational cost savings at GBPC and BLPC		4		13
Increased other income year over year primarily due to Q2 pre-tax gain recognized on the BLPC SIF regulatory liability (see details below)		3		43
Increased income tax expense primarily due to the gain recognized on the BLPC SIF regulatory liability		-		(9)
Other		(1)		-
Contribution to consolidated net income – 2016	**$**	**19**	$	**71**

The island of Grand Bahama took a direct hit from Hurricane Matthew in October 2016. Refer to the Caribbean Outlook section of this document for further details.

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 $22 million USD. As a result, Emera recorded a pre-tax gain of $41 million USD and an after-tax gain of $34 million USD. Absent this gain, the Emera Caribbean contribution to the consolidated net income for the nine months ended September 30, 2016 was $37 million USD ($49 million CAD).

Emera Caribbean's CAD contribution to consolidated net income increased by $11 million to $24 million in Q3 2016 compared to $13 million in Q3 2015 and year-over-year increased by $65 million to $92 million in 2016 compared to $27 million during the same period in 2015. The foreign exchange rate had no impact for the three months ended September 30, 2016. The impact of a stronger USD increased CAD earnings by $2 million for the nine months ended September 30, 2016.

Operating Revenues – Regulated Electric

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

Q3 Operating Revenues – Regulated Electric
millions of US dollars

		2016		2015
Electric revenues – base rates	**$**	**52**	$	50
Fuel charge		**36**		41
Total electric revenues		**88**		91
Other revenues		**1**		1
Operating revenues – regulated electric	**$**	**89**	$	92

YTD Operating Revenues – Regulated Electric
millions of US dollars

		2016		2015
Electric revenues – base rates	**$**	**143**	$	140
Fuel charge		**92**		119
Total electric revenues		**235**		259
Other revenues		**3**		3
Operating revenues – regulated electric	**$**	**238**	$	262

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q3 being the strongest period, reflecting warmer weather.

Q3 Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**129**	122	118
Commercial	**207**	198	196
Industrial	**25**	25	26
Other	**5**	4	6
Total	**366**	349	346

YTD Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**355**	338	329
Commercial	**581**	567	562
Industrial	**72**	79	76
Other	**16**	17	19
Total	**1,024**	1,001	986

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

Q3 Electric Revenues
millions of US dollars

	2016	2015	2014
Residential	**$ 30**	$ 31	$ 39
Commercial	**49**	51	66
Industrial	**7**	7	6
Other	**2**	2	2
Total	**$ 88**	$ 91	$ 113

YTD Electric Revenues
millions of US dollars

	2016	2015	2014
Residential	**$ 78**	$ 84	$ 109
Commercial	**133**	147	190
Industrial	**19**	23	19
Other	**5**	5	5
Total	**$ 235**	$ 259	$ 323

Electric revenues decreased $3 million to $88 million in Q3 2016 compared to $91 million in Q3 2015. Year-to-date, electric revenues decreased $24 million to $235 million in 2016 compared to $259 million during the same period in 2015. Highlights of the changes are summarized in the following table:

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Electric revenues – 2015	**$ 91**	**$ 259**
Decreased fuel charge revenues primarily due to lower fuel prices	(5)	(27)
Increased due to higher sales volumes at BLPC due to warmer weather	2	3
Electric revenues – 2016	**$ 88**	**$ 235**

Q3 Average Electric Revenue/MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 240**	$ 261	$ 328

YTD Average Electric Revenue/MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 229**	$ 259	$ 328

The change in average electric revenue per MWh in Q3 2016 compared to Q3 2015, and year-to-date in 2016 compared to the same periods in 2015 was the result of the decreased fuel charge due to lower fuel prices.

Electric Revenue and Margin

Emera Caribbean distinguishes revenues related to the recovery of fuel costs through the fuel charge from revenues related primarily to the recovery of non-fuel costs (“base rates”). Emera Caribbean’s electric margin and net income are influenced primarily by base rates, whereas the fuel charge and fuel costs do not have a material effect on electric margin or net income. Emera Caribbean’s customer classes contribute differently to the Company’s base rate revenue, with residential and commercial customers contributing more than industrial customers. Residential and commercial load is primarily affected by changes in weather and economic conditions, while industrial load is primarily affected by economic conditions.

Electric margin is summarized in the following table:

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Operating revenues – regulated electric	**$ 89**	$ 92	**$ 238**	$ 262
Less: Other revenues	**(1)**	(1)	**(3)**	(3)
Total electric revenues	**$ 88**	$ 91	**$ 235**	$ 259
Total electric revenues are broken down as follows:				
Electric revenues – base rate	**$ 52**	$ 50	**$ 143**	$ 140
Fuel charge	**36**	41	**92**	119
Total electric revenues	**88**	91	**235**	259
Regulated fuel for generation and purchased power	**37**	42	**94**	121
Regulatory amortization (1)	**1**	1	**2**	2
Electric margin	**$ 50**	$ 48	**$ 139**	$ 136

(1) Included in "Depreciation and amortization" on the Condensed Consolidated Statements of Income.

Emera Caribbean’s electric margin increased $2 million to $50 million in Q3 2016 compared to $48 million in Q3 2015 and year-to-date increased by $3 million to $139 million in 2016 compared to $136 million in 2015 due to increased sales volumes at BLPC as a result of warmer weather.

Q3 Average Electric Margin / MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 137**	$ 138	$ 136

YTD Average Electric Margin / MWh

US Dollars	**2016**	2015	2014
Dollars per MWh	**$ 136**	$ 136	$ 135

Emera Caribbean average electric margin is consistent period over period.

Regulated Fuel for Generation and Purchased Power

Q3 Production Volumes
GWh

	2016	2015	2014
Oil	**383**	379	368
Hydro	**9**	5	7
Solar	**5**	-	-
Total	**397**	384	375

YTD Production Volumes
GWh

	2016	2015	2014
Oil	**1,080**	1,072	1,048
Hydro	**27**	19	23
Solar	**5**	-	-
Total	**1,112**	1,091	1,071

Regulated fuel for generation and purchased power decreased $5 million to $37 million in Q3 2016 compared to $42 million in Q3 2015. Year-to-date decreased $27 million to $94 million in 2016 compared to $121 million during the same period in 2015 primarily due to lower commodity prices.

Q3 Average Fuel Costs/MWh			
US dollars	**2016**	2015	2014
Dollars per MWh	**$ 93**	$ 109	$ 175

YTD Average Fuel Costs/MWh			
US dollars	**2016**	2015	2014
Dollars per MWh	**$ 85**	$ 111	$ 175

The decrease in the average fuel costs in Q3 2016 and year-to-date compared to the same periods in 2015 was the result of lower commodity prices.

Non-GAAP Measure

Electric Margin Reconciliation

"Electric margin" is a non-GAAP financial measure used to show the amounts that BLPC, GBPC and Domlec retain to recover their non-fuel costs, as substantially all prudently incurred fuel costs are recovered from customers.

The companies' electric margin may not be comparable to electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. Management believes measuring electric margin shows the portion of revenues managed through fuel adjustment mechanism, which have a minimal impact on income. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance.

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Income from operations	**$ 22**	$ 17	**$ 49**	$ 36
Less:				
Operating revenues – non-regulated	**-**	2	**-**	6
Other revenue	**1**	1	**3**	3
Add back:				
Non-regulated direct costs	**-**	2	**-**	6
Operating, maintenance and general	**20**	24	**65**	78
Property taxes	**1**	-	**2**	1
Depreciation and amortization (1)	**8**	8	**26**	24
Electric margin	**$ 50**	$ **48**	**$ 139**	$ **136**

(1) Depreciation and amortization excludes $1 million of regulatory amortization in Q3 2016 (2015 – $1 million) and $2 million YTD in 2016 (2015 – $2 million).

EMERA ENERGY

Review of 2016

Emera Energy Adjusted Contribution to Consolidated Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Marketing and trading margin (1)	**$ 2**	$ 5	**$ 35**	$ 47
Electricity sales (2)	**94**	93	**351**	403
Total operating revenues – non-regulated	**96**	98	**386**	450
Non-regulated fuel for generation and purchased power (3)	**61**	54	**250**	248
Operating, maintenance and general	**20**	18	**64**	55
Provincial, state and municipal taxes	**4**	-	**7**	4
Depreciation and amortization	**11**	11	**32**	30
Total operating expenses	**96**	83	**353**	337
Adjusted income (loss) from operations	**-**	15	**33**	113
Income (loss) from equity investments (4)	**4**	7	**11**	23
Other income (expenses), net	**-**	2	**(2)**	24
Interest expense, net	**6**	6	**18**	13
Adjusted income (loss) before provision for income taxes	**(2)**	18	**24**	147
Income tax expense (recovery) (5)	**(2)**	3	**5**	52
Adjusted contribution to consolidated net income (loss)	**$ -**	$ 15	**$ 19**	$ 95
After-tax derivative mark-to-market gain (loss)	**$ (109)**	$ 13	**$ (98)**	$ (36)
Contribution to consolidated net income (loss)	**$ (109)**	$ 28	**$ (79)**	$ 59
Adjusted contribution to consolidated earnings per common share – basic	**$ -**	$ 0.10	**$ 0.12**	$ 0.65
Contribution to consolidated earnings per common share – basic	**$ (0.60)**	$ 0.19	**$ (0.50)**	$ 0.41
Adjusted EBITDA	**$ 15**	$ 35	**$ 74**	$ 190

(1) Marketing and trading margin excludes a pre-tax mark-to-market loss of $150 million in Q3 2016 (2015 - $5 million gain) and a loss of $139 million YTD in 2016 (2015 - $39 million loss)
(2) Electricity sales excludes a pre-tax mark-to-market loss of $4 million in Q3 2016 (2015 - $21 million gain) and a loss of $7 million YTD in 2016 (2015 - $17 million loss)
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $3 million in Q3 2016 (2015 - $4 million loss) and a gain of $5 million YTD in 2016 (2015 - $1 million loss)
(4) Income from equity investments excludes a pre-tax mark-to-market gain of $4 million YTD in 2015 (2016 - nil).
(5) Income tax expense (recovery) excludes a $48 million recovery relating to mark-to-market losses in Q3 2016 (2015 - $9 million expense) and a $43 million recovery relating to mark-to-market gains YTD in 2016 (2015 - $17 million recovery)

Mark-to-Market Adjustments

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

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

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

Emera Energy's contribution to consolidated net income decreased by $137 million to $(109)million in Q3 2016 compared to $28 million in Q3 2015 primarily due to a $122 million negative MTM change. Year-to-date, contribution to consolidated net income decreased $138 million to $(79) million in 2016 compared to $59 million during the same period in 2015 also primarily due to a negative MTM change of $62 million. Details 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 – 2015	**$ 28**	**$ 59**
Decreased marketing and trading margin reflects sustained low natural gas prices and volatility across the Northeast US and an increase in short-term fixed cost commitments for transportation and storage, partially mitigated by increased sales volumes	(3)	(12)
Decreased electricity sales year-over-year primarily due to lower hedged and market power prices at the NEGG Facilities, and lower market prices at Bayside Power, partially offset by higher sales volumes as a result of fewer planned outage hours at the Bridgeport Facility in 2016 and a stronger USD	1	(52)
Increased non-regulated fuel for generation and purchased power quarter-over-quarter primarily due to the expiry of a favourable gas contract at Bayside Power in 2016. Year-over-year also saw the recognition of $20 million in state fuel taxes for 2013 through March 2016, fewer planned outage hours at the Bridgeport Facility in 2016, and a stronger USD. These increases were offset by lower hedged and market commodity prices at the NEGG Facilities	(7)	(2)
Increased OM&G quarter-over-quarter primarily due to timing of outage work at the NEGG Facilities; year-over-year increase also due to a stronger USD, higher outage costs at the Maritime Canada Facilities (Brooklyn Energy and Bayside Power), and increased corporate costs, partially offset by decreased performance-based compensation resulting from decreased marketing and trading margin	(2)	(9)
Decreased income from equity investments - See Equity Investments section below	(3)	(12)
Decreased other income year-over-year primarily due to a one-time gain on the sale of NWP in 2015 and foreign exchange losses in marketing and trading due to the impact of strengthening CAD on CAD liabilities	(2)	(26)
Increased interest expense, net year-over-year due to intercompany loan due to Corporate and Other in Q2 2015	-	(5)
Decreased income tax expense primarily due to decreased income before provision for income taxes	5	47
Decreased mark-to-market, net of tax primarily due to changes in existing positions on long-term contracts and the amortization of 2015 gas transportation assets; year-over-year also partially offset by the reversal of 2015 mark-to-market losses and changes in gas and power contract positions	(122)	(62)
Other	(4)	(5)
Contribution to consolidated net income (loss) – 2016	**$ (109)**	**$ (79)**

A significant portion of Emera Energy earnings are exposed to foreign exchange fluctuations thereby affecting CAD dollar contribution to net earnings. The impact of the USD quarter-over-quarter decreased the loss in CAD by $1 million in Q3 2016 compared to Q2 2015. Year-to-date in 2016 the impact of the USD decreased the loss in CAD dollars by $12 million compared to the same period in 2015.

Energy Services

Adjusted EBITDA

Adjusted EBITDA for Emera Energy's marketing and trading business is summarized in the following

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Marketing and trading margin	**$ 2**	$ 5	**$ 35**	$ 47
OM&G	**4**	4	**16**	14
Other income (expenses), net	**-**	2	**(4)**	5
Adjusted EBITDA	**$ (2)**	$ 3	**$ 15**	$ 38

Marketing and Trading Margin

Marketing and trading margin decreased $3 million to $2 million in Q3 2016 compared to $5 million in Q3 2015. Margin was affected by sustained low natural gas prices and volatility. This was partially offset by increased volumes.

Year-to-date, marketing and trading margin decreased $12 million to $35 million in 2016 compared to $47 million during the same period in 2015. Higher Q1 2016 margin resulting from a stronger USD and growth in the volume of business mitigated the effect of sustained low natural gas prices and volatility, increased short-term transportation and storage costs overall in 2016.

Emera Energy Generation

Adjusted EBITDA

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

For the millions of Canadian dollars					Three months ended September 30	
	New England		Maritime Canada		Total	
	2016	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 67**	$ 67	**$ 15**	$ 15	**$ 82**	$ 82
Capacity and other	**12**	11	**-**	-	**12**	11
Electricity sales	**$ 79**	$ 78	**$ 15**	$ 15	**$ 94**	$ 93
Non-regulated fuel for generation and purchased power	**47**	45	**12**	7	**59**	52
Non-regulated electric margin	**32**	33	**3**	8	**35**	41
Provincial, state and municipal taxes	**3**	2	**-**	-	**3**	2
OM&G	**11**	7	**6**	5	**17**	12
Other income (expenses), net	**-**	-	**-**	1	**-**	1
Adjusted EBITDA	**$ 18**	$ 24	**$ (3)**	$ 4	**$ 15**	$ 28

For the millions of Canadian dollars						Nine months ended September 30
	New England		Maritime Canada			Total
	2016	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 257**	$ 303	**$ 57**	$ 68	**$ 314**	$ 371
Capacity and other	**37**	32	**-**	-	**37**	32
Electricity sales	**$ 294**	$ 335	**$ 57**	$ 68	**$ 351**	$ 403
Non-regulated fuel for generation and purchased power	**200**	205	**43**	41	**243**	246
Non-regulated electric margin	**94**	130	**14**	27	**108**	157
Provincial, state and municipal taxes	**5**	4	**-**	1	**5**	5
OM&G	**31**	24	**17**	14	**48**	38
Other income (expenses), net	**-**	1	**1**	-	**1**	1
Adjusted EBITDA	**$ 58**	$ 103	**$ (2)**	$ 12	**$ 56**	$ 115

Adjusted EBITDA for Emera Energy Generation decreased $13 million to $15 million in Q3 2016 from $28 million in Q3 2015; and year-to-date decreased $59 million to $56 million in 2016 from $115 million for the same period in 2015.

The NEGG Facilities EBITDA decreased $6 million quarter-over-quarter primarily due to timing of outage work and increased property tax expense at the Bridgeport Facility. Electric margin was consistent quarter-over-quarter. Year-to-date, the NEGG Facilities EBITDA decreased $45 million. This decrease includes a $20 million charge to cost of fuel to recognize fuel taxes for 2013 through March 2016. Absent this, the NEGG Facilities EBITDA would have been $78 million, a decrease of $25 million year-over-year. This reflects lower achieved spark spreads, primarily in Q1 2016 compared to the same period in 2015. This was partially offset by the stronger USD and fewer planned outage hours.

The Maritime Canada Facilities saw an increased cost of gas at Bayside Power, reflecting the expiry of a long-term favourable gas contract, and its replacement at market rates, which was the primary contributor to a $7 million reduction in EBITDA quarter-over-quarter; and a $14 million reduction year-over-year.

Operating Statistics

For the						Three months ended September 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**1,336**	1,295	**87.0%**	98.9%	**55.5%**	53.8%
Maritime Canada	**344**	376	**79.6%**	89.5%	**49.9%**	54.4%
Total	**1,680**	1,671	**85.3%**	96.8%	**54.2%**	53.9%

For the						Nine months ended September 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**3,950**	3,583	**91.7%**	96.1%	**55.1%**	50.7%
Maritime Canada	**1,293**	1,282	**87.3%**	91.8%	**62.9%**	62.4%
Total	**5,243**	4,865	**90.7%**	95.2%	**56.9%**	53.4%

(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 economic vis-à-vis the market.

Sales volumes and net capacity factor were consistent quarter-over-quarter; plant availability was lower, reflecting planned outages in Q3 2016. Year-over-year sales volume increase at the NEGG Facilities was primarily due to fewer planned outage hours in the first half of 2016 and an upgrade at the Bridgeport Energy Facility, completed in Q2 2015. This was partially offset year-over-year by the impact of weather across the northeastern United States. The Maritime Canada Facilities sales volumes and net capacity factor were consistent with the prior year.

The NEGG Facilities sell into price based competitive markets. The primary reason the overall capacity factor is lower as compared to the Maritime Canada Facilities is because the Rumford Plant, in particular, generally operates with a capacity factor of approximately 20 per cent, reflecting current electricity and gas supply price dynamics in its markets.

Adjusted income from equity investments

Adjusted income from equity investments is summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Bear Swamp	**$ 4**	$ 7	**$ 11**	$ 21
NWP	**-**	-	**-**	2
Adjusted income from equity investments	**$ 4**	$ 7	**$ 11**	$ 23

Adjusted income from equity investments decreased $3 million to $4 million in Q3 2016 compared to $7 million in Q3 2015 primarily due to higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing. Year-to-date, adjusted income from equity investments decreased $12 million to $11 million in 2016 compared to $23 million during the same period in 2015. This is primarily due to a resupply of contracted power sales in Bear Swamp in Q3 2015 that were not delivered in 2014 and higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing.

CORPORATE AND OTHER

Review of 2016

Corporate and Other

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Intercompany revenue (1)	**$ 9**	$ 10	**$ 29**	$ 24
Operating revenues – regulated gas	**1**	13	**26**	39
Non-regulated operating revenue	**11**	12	**27**	30
Non-regulated direct costs	**10**	11	**25**	33
Operating, maintenance and general	**89**	50	**124**	72
Depreciation and amortization	**1**	-	**3**	1
Total operating expenses	**100**	61	**152**	106
Income (loss) from operations	**(79)**	(26)	**(70)**	(13)
Income (loss) from equity investments	**18**	16	**66**	53
Other income (expenses), net (2)	**1**	1	**238**	1
Interest expense, net	**142**	12	**252**	36
Adjusted income (loss) before provision for income taxes	**(202)**	(21)	**(18)**	5
Income tax expense (recovery) (3)	**(65)**	(11)	**(65)**	(16)
Preferred stock dividends	**14**	15	**28**	30
Adjusted contribution to consolidated net income (loss)	**$ (151)**	$ (25)	**$ 19**	$ (9)
After-tax mark-to-market gain (loss)	**-**	(1)	**(116)**	(2)
Contribution to consolidated net income (loss)	**$ (151)**	$ (26)	**$ (97)**	$ (11)
Adjusted contribution to consolidated earnings per common share – basic	**(0.83)**	(0.17)	**0.12**	(0.06)
Contribution to consolidated earnings per common share – basic	**$ (0.83)**	$ **(0.18)**	**$ (0.60)**	$ (0.08)
Adjusted EBITDA	**$ (59)**	$ (9)	**$ 237**	$ 42

(1) Intercompany revenue consists of interest from EEG.

(2) Other income (expenses) net, excludes a pre-tax mark-to-market loss of $2 million in Q3 2016 (2015 - $1 million) and a loss of $135 million YTD in 2016 (2015 - $3 million).

(3) Income tax expense (recovery), excludes a $2 million recovery (2015 - nil) in Q3 2016 and a recovery of $19 million YTD in 2016 (2015 - $1 million) relating to mark-to-market gains (loss).

Mark-to-Market Adjustments

After-tax mark-to-market losses of $116 million for the nine months ended September 30, 2016 (2015 – $2 million) primarily relate to the effect of the Debenture Offering USD-denominated currency revaluation and forward contracts put in place to hedge the proceeds from the final instalment of the Debenture Offering. These losses offset a pre-tax mark-to-market gain of $119 million ($101 million after-tax gain) recorded in Q4 2015.

“Other income (expenses), net” and “Income tax expense (recovery)” are affected by the mark-to-market adjustments discussed above. Corporate and Other’s income table above shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

Corporate and Other contribution to consolidated net income decreased $125 million to $(151) million in Q3 2016 compared to $(26) million in Q3 2015. Year-to-date, Corporate and Other contribution to consolidated net income decreased $86 million to $(97) million in 2016 compared to $(11) million during the same period in 2015. Highlights of the 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 – 2015	**$ (26)**	**$ (11)**
Decreased operating revenue - regulated gas primarily as a result of accruing bill credits for NMGC customers as a result of the stipulation agreement on the closing of the TECO Energy acquisition	(12)	(13)
Increased OM&G primarily due to costs related to the TECO Energy acquisition offset by lower deferred compensation quarter over quarter and lower business development costs year over year	(39)	(52)
Income from equity investments – see table below for highlights	2	13
Gain on sale of APUC common shares, pre-tax	-	172
Gain on conversion of APUC subscription receipts and dividend equivalents into APUC common shares, pre-tax	-	63
Increased interest expense in Q3 primarily due to the Beneficial Conversion Feature recognized on conversion of the Convertible Debentures, year over year includes, interest on the Convertible Debentures and interest on a bridge facility used in the acquisition of TECO Energy	(55)	(141)
Post-acquisition interest on financing related to the TECO Energy acquisition	(75)	(75)
Increased income tax recovery primarily due to decreased income before provision for income taxes; year-over-year increase also due to the non-taxable portion of gains on APUC transactions and deferred income taxes on regulated income recorded as regulatory assets and liabilities	54	49
After-tax mark-to-market gain (loss) - see table below for highlights	1	(114)
Other	(1)	12
Contribution to consolidated net income (loss) – 2016	**$ (151)**	**$ (97)**

Acquisition Related Costs

Highlights of the TECO Energy related acquisition costs summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Operating revenues – regulated gas	**$ (10)**	$ -	**$ (10)**	$ -
Operating, maintenance, and general	**81**	30	**88**	30
Interest expense, net	**62**	1	**148**	1
Other income (expenses), net	**(3)**	3	**(3)**	3
Income tax expense (recovery)	**(37)**	(8)	**(70)**	(8)
Acquisition related costs	**$ 119**	$ 20	**$ 179**	$ 20

As part of the acquisition the Company has agreed to fund certain commitments in New Mexico. These commitments include contributions relating to economic development, donations, construction of an enlarged pipeline to the New Mexico/Mexico border, establishment of a matching fund to extend gas infrastructure in New Mexico and an annual customer bill reduction credit through June 30, 2018. In Q3 2016 Emera recognized $40 million ($23 million after-tax) associated with these commitments in "Operating revenues – regulated gas" and "Operating, maintenance, and general."

In addition to the New Mexico commitments, operating, maintenance, and general expenses includes acquisition related legal, accounting, banking and advisory fees and the accelerated vesting of outstanding stock-based compensation awards. Other income (expenses), net includes foreign exchange gains on acquisition related transactions. Interest expense, net includes interest incurred on the convertible debentures represented by instalment receipts and the acquisition credit facility issued for the purpose of financing the TECO Energy acquisition. In addition, it includes interest for the period between the issuance date and the acquisition date on acquisition-related long-term debt and the Beneficial Conversion Feature discount expensed on conversion of the convertible debentures.

After-Tax Mark-to-Market Gain (Loss)

The foreign currency earnings impact related to the translation of the TECO Energy acquisition related convertible debenture USD denominated cash balance and the mark-to-market adjustments from forward contracts from economically hedging the Debenture Offering are recorded as a mark-to-market adjustment. Pre-tax losses in 2016 of $135 million year-to-date ($116 million after-tax loss) are recorded in “Other income (expenses), net” on the Condensed Consolidated Statements of Income. These losses offset a pre-tax mark-to-market gain of $119 million ($101 million after-tax gain) recorded in Q4 2015. The after-tax mark-to-market gain (loss) is summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Foreign exchange on USD cash	**$ -**	$ -	**$ (43)**	$ -
Mark-to-market adjustment on interest rate hedges in EBP	**-**	(1)	**-**	(3)
Mark-to-market adjustment on USD forward contracts associated with the TECO Energy acquisition	**(2)**	-	**(92)**	-
Income tax (expense) recovery	**2**	-	**19**	1
After-tax mark-to-market gain (loss)	**$ -**	$ (1)	**$ (116)**	$ (2)

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	
	2016	2015	**2016**	2015
APUC	**$ -**	$ 4	**$ 18**	$ 19
M&NP	**6**	5	**17**	17
NSPML	**6**	4	**15**	11
LIL	**6**	3	**16**	6
Income from equity investments	**$ 18**	$ 16	**$ 66**	$ 53

Income from equity investments increased $2 million to $18 million in Q3 2016 compared to $16 million in Q3 2015. Year-to-date, income from equity investments increased $13 million to $66 million in 2016 compared to $53 million during the same period in 2015. 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
Income from equity investments – 2015	**$ 16**	**$ 53**
APUC – Sale of 50.1 APUC shares, no longer accounted for under equity method	(4)	(1)
M&NP	1	-
NSPML – Increase investment	2	4
LIL – Increase investment	3	10
Income from equity investments – 2016	**$ 18**	**$ 66**

Emera has invested approximately $1,087 million as at September 30, 2016 of equity, debt and working capital, including $117 million of AFUDC, in the development of the Maritime Link Project. Project to date, Emera has invested $272 million of equity, which is comprised of $225 million in equity contributed and $47 million of accumulated retained earnings, with the remaining costs being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent. Proceeds from the federally guaranteed debt financing completed in April 2014, were used to fund project costs until the Project's targeted debt to equity ratio reached 70 per cent to 30 per cent respectively, in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70 per cent to 30 per cent ratio, with equity contributions of $70 million year-to-date in 2016.

Emera has invested $326 million in the LIL as at September 30, 2016, which is comprised of $288 million in equity contributed and $38 million of accumulated equity earnings. Equity earnings are recorded based on an annual rate of 8.5 per cent (8.8 per cent prior to July 1, 2016). The rate is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities.

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 statements of cash flows between the nine months ended September 30, 2016 and 2015 include:

millions of Canadian dollars		**2016**		2015		$ Change
Cash and cash equivalents, beginning of period	**$**	**1,073**	$	221	$	852
Provided by (used in):						
Operating cash flow before change in working capital		**615**		591		24
Change in working capital		**252**		(29)		281
Operating activities		**867**		562		305
Investing activities		**(8,607)**		(101)		(8,506)
Financing activities		**7,157**		76		7,081
Effect of exchange rate changes on cash and cash equivalents		**(75)**		37		(112)
Cash and cash equivalents, end of period	**$**	**415**	$	795	$	(380)

Cash Flow from Operating Activities

Refer to Consolidated Income Statement and Operating Cash Flow Highlights for details.

Cash Flow Used In Investing Activities

Net cash used in investing activities increased $8,506 million to $8,607 million for the nine months ended September 30, 2016 compared to $101 million for the same period in 2015. The increase was primarily due to the acquisition of TECO Energy, proceeds from the sale of NWP in 2015, increased capital spending as a result of the acquisition of TECO Energy and increased investment in NSPML and LIL in 2016. This was partially offset by proceeds from the sale of APUC common shares in 2016.

Capital expenditures for the nine months ended September 30, 2016, including AFUDC and net of proceeds from disposal of assets, were $610 million compared to $320 million during the same period in 2015. The increase is a result of the acquisition of TECO Energy, additional capital spending in NSPI and the investment in a solar facility in Emera Caribbean. This was partially offset by less capital spending in the NEGG Facilities. Details of the capital spend are shown below:

- $246 million at Emera Florida and New Mexico;
- $225 million at NSPI (2015 – $180 million);
- $51 million at Emera Maine (2015 – $58 million);
- $63 million at Emera Caribbean (2015 – $26 million);
- $22 million at Emera Energy (2015 – $49 million);
- $3 million in Corporate and Other (2015 – $7 million)

Cash Flow from Financing Activities

Net cash provided by financing activities increased $7,081 million to $7,157 million for the nine months ended September 30, 2016 compared to $76 million for the same period in 2015. The increase was primarily due to the proceeds of the long-term debt issuance and convertible debentures related to the acquisition of TECO Energy and higher repayment of debt in 2015. This was partially offset by the 2015 proceeds of the long-term debt issuance by Brunswick Pipeline and increased 2016 dividends on common stock. The majority of the net cash provided by financing activities was used to finance the TECO Energy acquisition.

Contractual Obligations

As at September 30, 2016, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars		2016	2017	2018	2019	2020	Thereafter	Total
Long-term debt	$	255 $	444 $	751 $	1,351 $	870 $	11,001 $	14,672
Purchased power (1)		76	247	222	203	200	2,453	3,401
Fuel and gas supply		212	458	146	95	28	21	960
DSM		7	32	40	5	-	-	84
Pension and post-retirement obligations (2)		4	19	20	20	21	717	801
Asset retirement obligations		3	3	4	3	2	333	348
Interest payment obligations (3)		267	664	622	593	547	6,892	9,585
Convertible debentures represented by instalment receipts (4)		-	-	-	-	-	10	10
Transportation (5)		131	408	337	292	253	1,622	3,043
Long-term service agreements (6)		27	64	49	60	40	227	467
Capital projects		136	46	1	-	-	-	183
Equity investment commitments (7)		332	178	-	200	-	-	710
Leases and other (8)		9	46	16	14	13	35	133
	$	1,459 $	2,609 $	2,208 $	2,836 $	1,974 $	23,311 $	34,397

(1) Annual requirement to purchase electricity production from independent power producers over varying contract lengths.

(2) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2015. Credited service and earnings are assumed to be crystallized as at December 31, 2015. 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, 2015 to be eligible. As the defined benefit pension plans currently undergoes 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.

(3) 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, 2016, including any expected required payment under associated swap agreements.

(4) In 2015, to finance a portion of the acquisition of TECO Energy, Emera completed the sale of $2.185 billion aggregate principal amount of four per cent convertible unsecured subordinated debentures. As at September 30, 2016, a total of $2.175 billion aggregate principal had converted into common shares, leaving $10 million principal outstanding.

(5) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.

(6) 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.

(7) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") 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.

(8) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

Capital Structure

Emera targets a consolidated long-term capital structure of 55 per cent debt, 35 per cent common equity and 10 per cent preferred stock. Emera’s regulated subsidiaries maintain their own capital structures consistent with the respective regulator approved structure.

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.

As at September 30, 2016, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera – Operating and acquisition credit facility	June 2020 – Revolver	$ 700	$ 111	$ 589
Emera Florida and New Mexico - in USD - credit facilities	March - December 2018	1,300	612	688
NSPI – Operating credit facility	October 2020 – Revolver	600	279	321
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	36	44
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, 2016.

For the purpose of bridge financing for the acquisition of TECO Energy, on September 4, 2015, the Company secured an aggregate of $6.5 billion USD non-revolving term credit facilities (“Acquisition Credit Facilities”) from a syndicate of banks. The non-revolving term credit facilities were comprised of a $4.3 billion USD debt bridge facility, repayable in full on the first anniversary following its advance, and a $2.2 billion USD equity bridge facility repayable in full on the first anniversary following its advance.

On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD and on June 16, 2016, Emera further reduced the USD bridge facilities by $4.8 billion. On August 2, 2016, the Convertible Debentures Final Instalment Date, Emera obtained the remaining two-thirds of the Convertible Debentures instalment. The net proceeds were $1.4 billion and were used to fully repay the Company’s acquisition credit facility.

Emera’s future liquidity and capital needs will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, potential new acquisitions, dividends and debt servicing. These liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets.

Emera and its subsidiaries recent financing activity is discussed further in the Developments section of this MD&A, including the most recent capital markets transactions relating to the TECO Energy Acquisition.

Credit Ratings

Emera

In June, 2016 as result of the capital markets transactions outlined in the Developments section of this MD&A related to the TECO Energy acquisition, Moody's Investor Services assigned the following new credit ratings to Emera:

Issuer	Baa3 (Stable Outlook)
Senior Unsecured	Baa3
Subordinate	Ba2

Emera Florida and New Mexico

On July 6, 2016, Moody's downgraded the credit ratings of TECO Energy and TECO Finance to Baa2 from Baa1 and the issuer rating and senior unsecured ratings of TEC to A3 from A2. Moody's described the ratings outlook for the companies as stable.

On July 1, 2016, following the Merger with Emera, S&P affirmed the issuer credit ratings of TECO Energy and the senior unsecured debt ratings of its subsidiaries, TECO Finance, TEC and NMGC, and maintained the ratings outlook at negative.

On Oct. 9, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy at BBB and TEC at BBB+ and affirmed the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC. Fitch Ratings also described the ratings outlook as stable.

	S&P	Moody's	Fitch
TEC	BBB+	A3	A-
NMGC	BBB+	-	-
TECO Energy/TECO Finance	BBB	Baa2	BBB

Guarantees and Letters of Credit

There were no material changes in Emera's guarantees and letters of credit since December 31, 2015.

TECO Energy has letters of indemnity related to TECO Coal, which totaled $112 million ($85 million USD) at September 30, 2016. These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety.

The amounts outlined represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies. TECO Coal was sold on September 21, 2015 to Cambrian. Pursuant to the sales agreement, Cambrian Coal Corporation ("Cambrian") is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective. At the date of sale in September 2015, the letters of indemnity guaranteed $123 million ($94 million USD).

The company is working with Cambrian on the process to replace the 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.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. Below are transactions between Emera and its associated companies reported in the Condensed Consolidated Statements of Income:

For the millions of Canadian dollars			Three months ended September 30		Nine months ended September 30	
			2016	2015	**2016**	2015
	Nature of Service	**Presentation**				
Sales:						
APUC subsidiary (1)	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ -**	$ -	**$ 2**	$ 2
Purchases:						
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**1**	2	**2**	4
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**(6)**	(6)	**(21)**	(17)

(1) APUC subsidiary related party transactions includes transactions until May 24, 2016, when APUC ceased being a related party.

Operating revenue – non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate-regulated subsidiaries of Emera totaling $1 million for the three months ended September 30, 2016 (2015 $2 million) and $2 million for the nine months ended September 30, 2016 (2015 $2 million).

Amounts reported on Emera's Condensed Consolidated Balance Sheets due (to) from its equity investments are summarized in the following table:

As at millions of Canadian dollars	September 30 2016	December 31 2015
Due from related parties:		
NSPML – current	**$ 5**	$ 1
Subsidiary of APUC – current	**-**	1
M&NP – loan receivable – long-term	**3**	3
Due to related parties:		
M&NP – current	**2**	2
Net due from (to) related parties	**$ 6**	$ 3

All amounts are under normal interest and credit terms, except for a loan receivable from M&NP bearing interest at 1 per cent per annum maturing on November 30, 2019.

ENTERPRISE RISK AND RISK MANAGEMENT

Emera's risk management profile and practices have not changed materially from December 31, 2015, with the exception of the following risks:

Enterprise Resource Planning ("ERP") Implementation Risk

Certain Emera affiliates have begun the process to modernize their financial information systems through the implementation of an integrated ERP system. There are risks associated with this project, and the Company has adopted a detailed plan to address the risks inherent in the implementation process. The implementation of an ERP system will require the investment of significant financial and human resources. Disruptions, delays or 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. The Company has a dedicated project team, with executive oversight and a detailed governance structure. Consultants, with extensive ERP expertise, have and will continue to assist in planning, project management, implementation and training. The expected implementation date is in late 2017.

Project Development and Construction Risk

On July 20, 2016, NSPML announced a new transmission line contractor for the Maritime Link Project. The original contractor, Abengoa S.A., has been under ongoing global creditor protection proceedings that have hampered the company's ability to perform its work. As a result of Abengoa's failure to perform, NSPML placed Abengoa in default.

Abengoa's sureties administered a process to find a replacement contractor and NSPML has selected EUS-Rokstad, a joint venture between Emera Utility Services (an affiliate of Emera) and Rokstad Power to complete construction of the High Voltage Direct Current (HVdc) transmission line. Each parent company of the joint venture parties will be providing a guarantee to the other member of the joint venture as security for the obligations of its subsidiary under the joint venture agreement.

EUS has deployed a robust project and risk management approach to the contract led by a team with experience in large projects. As part of the agreement to be entered into with NSPML, EUS will have responsibility for approximately 50 kilometers of HVdc transmission line in Nova Scotia and Rokstad will be responsible for approximately 140 kilometers of HVdc transmission line on the island of Newfoundland.

Capital Market and Liquidity Risk

Emera's utility and non-utility operations and projects in development require significant capital investments in property, plant and equipment. Consequently, Emera is an active participant in the debt and equity markets. After giving effect to the TECO Energy acquisition, Emera now has total debt of $15 billion. Any disruption in capital markets could have a material impact on Emera's ability to fund its operations. Capital markets are global in nature and are affected by numerous events throughout the world economy. Capital market disruptions could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera forecasts cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed ordinary course capital needs.

Emera is subject to financial risk associated with changes in its credit ratings. A change to a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations.

Integration Risk

On July 1, 2016, Emera closed the acquisition of TECO Energy. Integration of this acquisition involves a number of risks, including failure to integrate successfully the personnel, technology, and operations of the acquired business, failure to maximize the potential financial and strategic benefits of the transaction, possible impairment of relationships with employees and customers, potential loss of key personnel as a result of uncertainty about their future roles, and reductions in future operating results from impairment of goodwill. Emera mitigates these risks by following systematic procedures for integrating acquisitions and subjecting the process to close monitoring and review by the Board of Directors.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. 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, Emera manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and capital projects. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

The Company does not utilize derivative financial instruments for trading or speculative purposes, or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries are included in accumulated other comprehensive income (loss) ("AOCI").

In 2015, approximately 50 per cent of Emera's adjusted net income was derived from subsidiaries with US functional currency. As such, its earnings are subject to fluctuations in the Canadian dollar to US dollar exchange rate. The July 1, 2016 acquisition of TECO Energy has increased this percentage to approximately 70 per cent. The operations of TECO Energy are conducted in US dollars, thus Emera's consolidated net income and cash flows are impacted to a greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar, could negatively impact the Company's net income as reported in Canadian dollars.

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, activities of third parties, damage to facilities and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties and damage to the pipelines facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence. Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could adversely affect the Company's results of operations and cash flows.

Deferred Tax Benefits Risk

The value of Emera's existing deferred tax benefits are determined by existing tax laws and could be negatively impacted by changes in these laws. "Comprehensive tax reform" remains a topic of discussion in the U.S. Congress. Such legislation could significantly alter the existing tax code, including a reduction in corporate income tax rates. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would reduce the value of the Company's existing deferred tax assets and could result in a charge to earnings from any write-down.

FINANCIAL INSTRUMENTS

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 2016**		December 31 2015
Derivative instrument assets (current and other assets)	**$**	**11**	$	20
Derivative instrument liabilities (current and long-term liabilities)		**(26)**		(46)
Net derivative instrument assets (liabilities)	**$**	**(15)**	$	(26)

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		
		2016		2015		**2016**		2015
Operating revenues – regulated	**$**	**(3)**	$	(3)	**$**	**(8)**	$	(6)
Non-regulated fuel for generation and purchased power		**(1)**		(1)		**2**		4
Income from equity investments		**-**		-		**(1)**		(1)
Effective net gains (losses)	**$**	**(4)**	$	(4)	**$**	**(7)**	$	(3)

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 2016**		December 31 2015
Derivative instrument assets (current and other assets)	**$**	**176**	$	210
Regulatory assets (current and other assets)		**24**		64
Derivative instrument liabilities (current and long-term liabilities)		**(25)**		(64)
Regulatory liabilities (current and long-term liabilities)		**(175)**		(210)
Net asset (liability)	**$**	**-**	$	-

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		
		2016		2015		**2016**		2015
Regulated fuel for generation and purchased power (1)	**$**	**(2)**	$	10	**$**	**-**	$	24
Net gains (losses)	**$**	**(2)**	$	10	**$**	**-**	$	24

(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 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 2016**		December 31 2015
Derivative instruments assets (current and other assets)	**$**	**43**	$	96
Derivative instruments liabilities (current and long-term liabilities)		**(232)**		(332)
Net derivative instrument assets (liabilities)	**$**	**(189)**	$	(236)

Held-for-trading Items Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended September 30				Nine months ended September 30		
		2016		2015		**2016**		2015
Operating revenue - non-regulated	**$**	**(38)**	$	44	**$**	**219**	$	116
Non-regulated fuel for purchased power		**(3)**		(4)		**-**		(8)
Net gains (losses)	**$**	**(41)**	$	40	**$**	**219**	$	108

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 2016**	December 31 2015
Derivative instrument assets (current and other assets)	**$ -**	$ 92
Derivative instrument liabilities (current and long-term liabilities)	**(3)**	(3)
Net derivative instrument assets (liabilities)	**$ (3)**	$ 89

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	
	2016	2015	**2016**	2015
Interest expense, net	**$ -**	$ (1)	**$ -**	$ (3)
Other income (expense)	**15**	-	**(87)**	-
Total gains (losses)	**$ 15**	$ (1)	**$ (87)**	$ (3)

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.* Our internal control framework is based on the criteria published in the report Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management, including the CEO and Chief Financial Officer, evaluated the design of our DC&P and ICFR as at September 30, 2016, to provide reasonable assurance regarding the reliability of financial reporting in accordance with United States Generally Accepted Accounting Principles.

There were no changes in the Company's ICFR during the quarter ended September 30, 2016, which have materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting, except as outlined below.

Limitation on Scope of Design

The Company has limited the scope of design of DC&P and ICFR to exclude controls, policies and procedures relating to TECO Energy (including its holdings Tampa Electric, PGS and NMGC) which was acquired on July 1, 2016 (refer to Note 5 for segmented financial information). National Instrument 52-109 permits a business that the issuer acquires not more than 365 days before the issuer's financial year-end to be excluded from its scope of certifications. TECO Energy, including its holdings, continues to evaluate the effectiveness of its DC&P quarterly and ICFR annually in accordance with the Sarbanes Oxley Act of 2002.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with United States 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, asset removal costs, inventory, changes in assumptions within goodwill impairment assessments, income taxes, including deferred taxes, asset retirement obligations, capitalized overhead and valuation of derivative instruments and investments and contingencies. Actual results may differ significantly from these estimates.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and were adopted by the Company, with no material impact on its consolidated financial statements year-to-date in 2016, are described as follows:

Consolidation
In February 2015, the FASB issued Accounting Standard Update ("ASU") 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity ("VIE") characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities were subject to re-evaluation under the revised consolidation model.

Interest – Imputation of Interest
In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. The Company adopted this standard in Q1 2016 and December 31, 2015 balances have been retrospectively restated. This change resulted in $62.3 million of debt issuance costs, as at December 31, 2015, previously presented as "Other long-term assets", being reclassified as a deduction from the carrying amount of the related long-term debt and "Convertible debentures" on its Condensed Consolidated Balance Sheets.

In accordance with ASU 2015-15 *Interest: Imputation of Interest*, the Company continues to present debt issuance costs related to its revolving credit facilities and related instruments in "Other long-term assets" on its Condensed Consolidated Balance Sheets.

Compensation – Retirement Benefits
In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates.

Intangibles – Goodwill and Other – Internal-Use Software
In April 2015, the FASB issued ASU 2015-05, *Intangibles* **–** *Goodwill and Other* **–** *Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, the customer would account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer would account for the arrangement as a service contract. The guidance does not change USGAAP for a customer's accounting for service contracts.

Inventory – Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU 2015-11, *Inventory – Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. The Company early adopted in 2016 as permitted.

Derivatives and Hedging – Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships
In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships*. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The Company early adopted in 2016 as permitted.

Investments – Equity Method and Joint Ventures
In March 2016, the FASB issued ASU 2016-07, *Investments – Equity Method and Joint Ventures*, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. The Company early adopted in 2016 as permitted.

Compensation – Stock Compensation
In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation* to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, accounting for forfeitures, classification of awards as either equity or liabilities and presentation on the statement of cash flows. The Company early adopted in 2016 as permitted.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or are not expected to have a material impact on the consolidated financial statements.

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. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled to. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018. The Company has developed an implementation plan and is continuing to evaluate the available adoption methods and the impact of adoption of this standard on its consolidated financial statements and disclosures.

Financial Instruments – 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 Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases
In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard 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 lease assets and lease liabilities on the balance sheet. The effect of leases on the Condensed Consolidated Statements of Income and the Condensed Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments
In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective beginning in 2020, with early adoption permitted in 2019, and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows
In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for the company beginning in 2018, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q3 2016***	Q2 2016	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014
Operating revenues	**$ 1,387**	$ 499	$ 877	$ 732	$ 642	$ 527	$ 889	$ 783
Net income (loss) attributable to common shareholders	**(95)**	208	44	192	35	10	160	151
Adjusted net income attributable to common shareholders	**14**	238	120	87	23	48	172	79
Earnings per common share – basic	**(0.52)**	1.39	0.30	1.31	0.24	0.07	1.10	1.05
Earnings per common share – diluted	**(0.52)**	1.38	0.30	1.30	0.24	0.07	1.09	1.02
Adjusted earnings per common share – basic	**0.08**	1.59	0.81	0.59	0.16	0.33	1.18	0.54

* Q3 2016 financial results include Emera Florida and New Mexico.

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. Historically, the first quarter is generally 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 will provide stronger earnings contributions due to the summer being the peak electricity season in Florida. As the energy industry is seasonal in nature for companies like Emera, 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 be affected by items outlined in the Significant Items section and mark-to-market adjustments.