Management’s Discussion & Analysis

As at August 8, 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 second quarter of 2016 relative to 2015; and its financial position as at June 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 six months ended June 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	
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")	Government of St. Lucia

All amounts are in Canadian dollars ("CAD"), except for the Emera Maine and Emera Caribbean sections of the MD&A, which are reported in US dollars ("USD"), unless otherwise stated.

Additional information related to Emera, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com.

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; derivative financial instruments and hedging availability; impact of acquisition related expenses; 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; followed by the Consolidated Financial Review and Outstanding Common Stock data; then presents information specific to Emera's consolidated subsidiaries and investments.

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

- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and its parent company, Emera (Caribbean) Incorporated ("ECI"), GBPC, and Lucelec;
- Pipelines includes Brunswick Pipeline and M&NP;
- 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"), 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;
    - Acquisition costs related to TECO Energy;
    - 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, Outlook, 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 that invests in electricity generation, transmission and distribution, gas transmission and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States and the Caribbean. Emera is targeting eight-per-cent annual dividend growth through 2020.

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. 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 have 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 New England Gas Generating 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 create 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 strong 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 income (a non-GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows that fund dividends, reinvestment and which is reflective of the Company's risk tolerance. The Company is expected to achieve its 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 that do not qualify for hedge accounting or regulatory accounting 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.

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	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 the TECO Energy acquisition convertible debentures 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, Pipelines – 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Net income attributable to common shareholders	**$ 207.8**	$ 10.0	**$ 252.1**	$ 170.1
After-tax mark-to-market gain (loss)	**$ (29.7)**	$ (38.0)	**$ (105.6)**	$ (49.5)
Adjusted net income attributable to common shareholders	**$ 237.5**	$ 48.0	**$ 357.7**	$ 219.6
Earnings per common share – basic	**$ 1.39**	$ 0.07	**$ 1.69**	$ 1.17
Adjusted earnings per common share – basic	**$ 1.59**	$ 0.33	**$ 2.40**	$ 1.51

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, NSPI, Emera Maine, Emera Caribbean, Pipelines, Emera Energy, and Corporate and Other sections.

EBITDA and Adjusted EBITDA Reconciliation

For the millions of Canadian dollars	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Net income	**$ 216.8**	$ 22.4	**$ 271.6**	$ 196.5
Interest expense, net	**107.3**	48.0	**182.5**	92.4
Income tax expense (recovery)	**1.1**	(1.4)	**27.9**	60.0
Depreciation and amortization	**84.5**	84.3	**172.0**	167.1
EBITDA	**409.7**	153.3	**654.0**	516.0
Mark-to-market gain (loss), excluding income tax and interest	**(41.7)**	(52.6)	**(116.8)**	(74.1)
Adjusted EBITDA	**$ 451.4**	$ 205.9	**$ 770.8**	$ 590.1

Electric Margin

"Electric margin" is a non-GAAP financial measure used to show the amounts that NSPI, BLPC, GBPC and Domlec retain to recover non-fuel costs. Prudently incurred fuel costs are recovered from customers, except at Domlec, where substantially all fuel costs are passed to customers through the fuel pass-through mechanism. Management believes measuring electric 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 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, 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 is discussed further in the NSPI – Electric Margin, the Emera Caribbean – Electric Margin and the Emera Energy – Adjusted EBITDA sections.

Significant Items Affecting Earnings

2016

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 $543.9 million. This sale resulted in a pre-tax gain of $172.1 million or $1.15 per common share (after-tax gain of $145.5 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 $62.8 million or $0.42 per common share (after-tax gain of $53.1 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 $28.6 million ($22.0 million USD). As a result, Emera recorded a pre-tax gain of $53.1 million ($41.2 million USD) or $0.35 per common share and an after-tax gain of $43.4 million ($33.7 million USD) or $0.29 per common share in "Other income (expenses), net". In Q3 2016, Emera received $65.0 million ($50.0 million USD).

Emera Energy Recognition of State Fuel Taxes

Emera Energy recorded a $19.9 million pre-tax or $0.13 per common share ($11.8 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 $3.5 million pre-tax ($2.1 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 decreased $8.3 million to $29.7 million in Q2 2016 compared to $38.0 million in Q2 2015 and increased $56.1 million to $105.6 million year-to-date in 2016 compared to $49.5 million for the same period in 2015. Year-over-year increased losses are primarily due to the translation of the TECO Energy related Convertible Debentures USD-denominated currency and the associated forward contracts and the amortization of 2015 Emera Energy gas transportation assets. This increase was partially offset by the reversal of mark-to-market losses and changes in gas and power contract positions at Emera Energy.

Acquisition Related Costs

Emera incurred after-tax costs related to its acquisition of TECO Energy (“the Acquisition”), including legal, advisory, and financing costs of $42.0 million ($0.28 per common share) in Q2 2016 and $59.5 million year-to-date ($0.40 per common share).

As discussed and included above 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 were recorded as a mark-to-market after-tax gain of $4.9 million in Q2 2016 and an after-tax loss of $116.2 year-to-date in 2016 in “Other income (expenses), net”.

2015

Barbados Light & Power Company Limited (“BLPC”) Restructuring Costs

BLPC recorded severance costs of $7.9 million ($6.4 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 $5.4 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 $282.3 million ($223.3 million USD). This sale resulted in a pre-tax gain of $18.6 million or $0.13 per common share (after-tax gain of $11.5 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 June 30	Six months ended June 30
Adjusted net income – 2015	**$ 48.0**	**$ 219.6**
Gain on sale of APUC common shares	145.5	145.5
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	53.1	53.1
Gain on BLPC SIF regulatory liability	43.4	43.4
NSPI	11.5	(4.0)
2015 gain on the sale of NWP	-	(11.5)
Emera Energy's recognition of fuel taxes for 2013 through March 2016	(11.8)	(11.8)
Emera Energy	(20.3)	(37.3)
Acquisition and financing costs related to the acquisition of TECO Energy	(42.0)	(59.5)
Other	10.1	20.2
Adjusted net income – 2016	**$ 237.5**	**$ 357.7**

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Operating revenues	**$ 499.4**	$ 526.9	**$ 1,376.4**	$ 1,415.4
Income from operations	**0.7**	36.1	**270.7**	268.2
Net income attributable to common shareholders	**207.8**	10.0	**252.1**	170.1
After-tax mark-to-market gain (loss)	**(29.7)**	(38.0)	**(105.6)**	(49.5)
Adjusted net income attributable to common shareholders	**$ 237.5**	$ 48.0	**$ 357.7**	$ 219.6
Earnings per common share – basic	**$ 1.39**	$ 0.07	**$ 1.69**	$ 1.17
Earnings per common share – diluted	**$ 1.38**	$ 0.07	**$ 1.68**	$ 1.16
Adjusted earnings per common share – basic	**$ 1.59**	$ 0.33	**$ 2.40**	$ 1.51
Dividends per common share declared	**$ 0.4750**	$ 0.4000	**$ 0.9500**	$ 0.7875
Adjusted EBITDA	**$ 451.4**	$ 205.9	**$ 770.8**	$ 590.1

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30		Six months ended June 30	
Operating Unit Contributions to Adjusted Net Income	**2016**	2015	**2016**	2015
NSPI	**$ 28.4**	$ 16.9	**$ 80.9**	$ 84.9
Emera Maine	**9.7**	13.7	**19.0**	25.2
Emera Caribbean	**58.1**	4.8	**67.9**	13.6
Pipelines	**8.3**	9.3	**18.0**	19.2
Emera Energy	**(28.7)**	3.4	**19.2**	79.8
Corporate and Other	**161.7**	(0.1)	**152.7**	(3.1)
Adjusted net income attributable to common shareholders	**$ 237.5**	$ 48.0	**$ 357.7**	$ 219.6
After-tax mark-to-market gain (loss)	**(29.7)**	(38.0)	**(105.6)**	(49.5)
Net income attributable to common shareholders	**$ 207.8**	$ 10.0	**$ 252.1**	$ 170.1

For the millions of Canadian dollars	Six months ended June 30	
	2016	2015
Operating cash flow before changes in working capital	**$ 325.0**	$ 435.1
Change in working capital	**150.7**	(85.3)
Operating cash flow	**$ 475.7**	$ 349.8
Investing cash flow	**$ 178.2**	$ 63.7
Financing cash flow	**$ 5,809.8**	$ (481.0)

As at millions of Canadian dollars	**June 30 2016**	December 31 2015
Working capital	**$ 303.5**	$ 599.2
Total assets	**$ 18,988.7**	$ 11,950.0

Q2 Consolidated Income Statement Highlights

Operational Results

Income from operations decreased $35.4 million to a loss of $0.7 million in Q2 2016 compared to $36.1 million in Q2 2015 primarily due to the recording of the $19.9 million liability for state tax on natural gas sales made from November 2013 through March 2016 in non-regulated fuel for generation and purchased power at Emera Energy's New England Gas Generating Facilities and decreased marketing and trading margin reflecting weak natural gas market conditions.

Details of operating revenues and operating expenses line item variances are described below:

Total operating revenues decreased 5.2 per cent to $499.4 million in Q2 2016 compared to $526.9 million in Q2 2015, primarily due to:

- $17.0 million decrease in Emera Energy Services reflecting weak natural gas market conditions;
- $12.6 million decrease in NSPI primarily as a result of lower sales volumes due to load and decreased electricity pricing;
- $5.5 million decrease from changes in mark-to-market impacts;
- $4.0 million decrease at BLPC primarily as a result of decreased fuel revenues due to lower fuel prices;
- $18.5 million increase at the New England Gas Generating Facilities primarily due to fewer planned outage hours at Bridgeport Energy in 2016.

Total operating expenses increased 1.6 per cent to $498.7 million in Q2 2016 compared to $490.8 million in Q2 2015, primarily due to increased fuel costs at the New England Gas Generating Facilities, including the state tax issue discussed above and the impact of a stronger USD, partially offset by decreased fuel costs at NSPI and BLPC.

Other income (expenses), net

Other income in Q2 2016 increased $293.5 million to $294.2 million compared to $0.7 million in the same period in 2015. This was primarily due to a $172.1 million gain on the sale of 50.1 million common shares of APUC, a $62.8 million gain on conversion of 12.9 million APUC subscription receipts and dividend equivalents into common shares, and a $53.1 million gain on the BLPC SIF regulatory liability.

Interest expense, net

Interest expense, net increased $59.3 million in Q2 2016 to $107.3 million compared to $48.0 million in the same period in 2015, primarily due to interest expense on the TECO Energy acquisition related Convertible Debentures.

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

Operational Results

Income from operations increased $2.5 million to $270.7 million year-to-date ("YTD") in 2016 compared to $268.2 million during the first six months in 2015 primarily due to mark-to-market gains of $94.5 million, partially offset by decreased margin at the New England Gas Generating Facilities, including the state tax issue discussed above, decreased income from operations at NSPI and decreased marketing and trading margin at Emera Energy Services.

Details of the operating revenues and operating expenses line item variances are described below:

Total operating revenues decreased 2.8 per cent to $1,376.4 million year-to-date in 2016 compared to $1,415.4 million in 2015 primarily due to:

- $61.6 million decrease at NSPI as a result of decreased sales volumes due to weather and lower load;
- $41.6 million decrease at the New England Gas Generating Facilities reflecting lower hedged and market commodity prices, partially offset by fewer outage hours at Bridgeport Energy in Q2 2016;
- $11.4 million decrease at Bayside primarily due to lower power prices;
- $90.4 million increase from changes in mark-to-market impacts.

Total operating expenses decreased 3.6 per cent to $1,105.7 million year-to-date in 2016 compared to $1,147.2 million for the same period in 2015. This was primarily a result of decreased fuel costs at NSPI reflecting lower commodity prices and lower load due to weather and decreased fuel costs at BLPC reflecting lower commodity prices, partially offset by the impact of a stronger USD.

Other income (expenses), net

Other income increased $132.4 million to $155.0 million year-to-date in 2016 compared to $22.6 million for the same period in 2015. This was primarily due to a $172.1 million pre-tax gain on the sale of 50.1 million common shares of APUC, a $62.8 million pre-tax gain on conversion of 12.9 million APUC subscription receipts and dividend equivalents, and a $53.1 million gain on the BLPC SIF regulatory liability. This was partially offset by mark-to-market losses relating to the effect of TECO Energy related convertible debenture USD-denominated currency and forward contracts put into place to economically hedge anticipated proceeds from the Debenture Offering financing and the 2015 gain on the sale of NWP.

Interest expense, net

Interest expense, net increased $90.1 million year-to-date in 2016 to $182.5 million compared to $92.4 million in 2015, primarily due to interest expense on the TECO Energy acquisition related Convertible Debentures.

Income tax expense (recovery)

Income tax expense decreased $32.1 million to $27.9 million year-to-date compared to $60.0 million for the same period in 2015 primarily due to the non-taxable portion of gains on APUC transactions and the lower foreign tax rate applicable to the gain on the BLPC SIF regulatory liability. This was partially offset by increased income before provision for income taxes and the non-deductible portion of mark-to- market losses on USD-denominated currency and forward contracts related to the TECO Energy acquisition.

Operating Activities

Net cash provided by operating activities year-to-date in 2016 increased $125.9 million to $475.7 million compared to $349.8 million during the same period in 2015. Cash from operations before changes in working capital decreased by $110.1 million primarily due to acquisition and financing costs related to TECO Energy, decreased margin at the New England Gas Generating Facilities, including the state tax issue discussed above and lower distributions at Bear Swamp. This was partially offset by the impact of a strengthening USD.

Changes in working capital increased operating cash flows by $236.0 million primarily due to favourable changes in posted margin at NSPI and Emera Energy Services, the timing of income taxes at NSPI and Emera Energy Services, decreased fuel inventory and receivables as a result of lower sales at NSPI and the impact of a stronger USD.

Effect of Foreign Currency Translation

Emera’s foreign currency-denominated results are affected by exchange rate fluctuations. Revenue, operating expense, net income, and adjusted net income are translated at the weighted average rate of exchange. The amounts in the table below are calculated by multiplying the current period foreign denominated results by the change in the weighted average foreign exchange from the prior period. The table below shows the estimated effect of foreign currency translation on key income statement items:

millions of Canadian dollars (except per share amounts)	Q2 2016 vs Q2 2015	Q2 2015 vs Q2 2014
Impact on income from continuing operations		
Total operating revenues	$ 6.9	$ 19.4
Total operating expenses	(9.6)	(22.1)
Net income	(0.1)	(0.9)
Adjusted net income	1.8	3.1
Impact on earnings per share		
Basic	$ -	$ -
Adjusted	$ 0.01	$ 0.02

millions of Canadian dollars (except per share amounts)	2016 vs 2015	2015 vs 2014
Impact on income from continuing operations		
Total operating revenues	$ 55.3	$ 62.7
Total operating expenses	(35.3)	(54.6)
Net income	15.6	8.3
Adjusted net income	9.0	14.1
Impact on earnings per share		
Basic	$ 0.10	$ 0.06
Adjusted	$ 0.06	$ 0.10

Emera's weighted average foreign exchange rates are shown in the following table:

			Six months ended June 30
Average equivalent of $1.00 USD	2016	2015	2014
CAD	$ 1.34	$ 1.23	$ 1.11

Consolidated Balance Sheets Highlights

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ 6,385.5**	Increased primarily due to the proceeds received from the issuance of TECO Energy acquisition related debt and the sale of APUC common shares. The increase in cash will be used to finance the TECO Energy acquisition
Instalment receipts receivable	**1,457.4**	Increased due to the recognition of the final instalment associated with the Convertible Debentures related to the TECO Energy acquisition
Receivables, net	**(97.8)**	Decreased due to seasonal trends of business at Emera Energy and NSPI
Inventory	**(48.5)**	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)	**(203.6)**	Decreased primarily due to settlements of derivative instruments at Emera Energy and NSPI and mark-to-market adjustments on the hedges on the anticipated proceeds from the final instalment of the Debenture Offering related to the TECO Energy acquisition
Prepaid expenses	**27.0**	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	**(114.3)**	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	**(386.6)**	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)	**148.0**	Increased primarily due to the reclassification of the outstanding APUC common shares from "Investments subject to significant influence"
Other assets (current and long-term)	**(137.2)**	Decreased primarily due to the amortization of transportation/storage capacity assets at Emera Energy
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**5,857.7**	Increased primarily due to the issuance of long-term debt related to the TECO Energy acquisition
Convertible debentures represented by instalment receipts	**1,395.9**	Increased due to the recognition of the final instalment on the Convertible Debentures related to the TECO Energy acquisition as a result of the issuance of the final instalment notice. This was partially offset by the beneficial conversion feature discount associated with the Debentures
Deferred income tax liabilities, net of deferred income tax assets	**46.7**	Increased primarily due to accelerated tax deductions related to property, plant and equipment at NSPI and the beneficial conversion feature discount on the Convertible Debentures related to the TECO Energy acquisition
Derivative instruments (current and long-term)	**(243.2)**	Decreased primarily due to settlements of natural gas and power contracts at Emera Energy
Regulatory liabilities (current and long-term)	**(76.1)**	Decreased primarily due to the reduction of the BLPC SIF regulatory liability and changes in regulated derivatives, partially offset by an increased FAM regulatory liability at NSPI
Common stock	**66.4**	Increased primarily due to issuance of common stock for the dividend reinvestment program
Contributed surplus	**45.7**	Increased primarily due to the beneficial conversion feature discount on the convertible debentures related to the TECO Energy acquisition

Accumulated other comprehensive income	**(184.6)**	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	**116.7**	Increased due to net income in excess of dividends paid
Non-controlling interest in subsidiaries	**(27.4)**	Decreased due to increased ownership by Emera in ECI

Developments

Emera

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 will be 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 facilities. 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 fully repay the Company's acquisition credit facility.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy's holdings include Tampa Electric, an integrated regulated electric utility that serves approximately 730,000 customers in West Central Florida, Peoples Gas System, a regulated gas distribution utility that serves more than 370,000 customers across Florida, and New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility that serves more than 520,000 customers across New Mexico.

The acquisition of TECO Energy allows Emera to further diversify its regulated assets, net income and cash flows in growth markets and constructive regulatory environments, while furthering its strategic objective to supply customers with generation from cleaner sources. The acquisition is also supportive of Emera's target of achieving 75 to 85 per cent of its adjusted net income from rate-regulated subsidiaries.

On April 11, 2016, Emera and TECO Energy filed with the New Mexico Public Regulation Commission ("NMPRC") an unopposed stipulation agreement reflecting a settlement reached with certain intervening parties in the acquisition. On May 2, 2016, the Hearing Examiner held a hearing to consider the stipulation agreement. The Hearing Examiner filed a Certificate of Stipulation on June 8, 2016, recommending approval of the stipulation to which all intervenors had either consented to or filed a notice of non-opposition. On June 22, 2016, the NMPRC approved the stipulation, and an order was entered on that same day.

As part of the stipulation agreement filed with the NMPRC noted above, NMGC agreed, among other things, to fund, at shareholder expense, economic development projects, make charitable contributions, provide funding to enterprises engaged in economic and business development in New Mexico, apply annual bill reduction credits through June 30, 2018, to construct an enlarged pipeline from NMGC's current system to the New Mexico/Mexico border, and establish a matching fund to extend its natural gas infrastructure to currently unserved areas in New Mexico. Approximately $30.4 million USD ($18.5 million USD after-tax) associated with these commitments will be recorded in the third quarter of 2016.

The acquisition of TECO Energy is expected to be accretive to EPS by approximately five per cent in 2017, growing to more than 10 per cent by 2019, assuming a CAD/USD exchange rate consistent with that at the time of the acquisition announcement.

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 $172.1 million or $1.15 per common share (after-tax gain of $145.5 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 $62.8 million or $0.42 per common share (after-tax gain of $53.1 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 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 $15.3 million ($23.4 million BBD), consisting of $14.4 million of the Cash Offer ($22.0 million BBD) and $0.9 million of the DR Offer ($1.4 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:

$500,000,000 USD three year, 2.15 per cent Notes due 2019
$750,000,000 USD five year 2.70 per cent Notes due 2021
$750,000,000 USD ten year 3.55 per cent Notes due 2026
$1,250,000,000 USD 30 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 June 30, 2016, the carrying value of the U.S., Hybrid, and Canadian Notes issued amounted to $6,210 million, and was recorded in "Long-term debt" on the 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 will join the Emera Board of Directors. Mr. Ramil is President and Chief Executive Officer ("CEO") of TECO Energy until his retirement on August 31, 2016.

Executive

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

Effective August 1, 2016, Bob Hanf has been appointed to the new role of Executive Vice President, Stakeholder Relations and Regulatory Affairs for Emera. Mr. Hanf will oversee strategy and alignment for all teams across the Emera companies in the areas of stakeholder and regulatory relations, safety, environment, communications and government relations. Most recently, he was President and CEO of NSPI.

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

Effective July 13, 2016, Rob Bennett will serve as Chief Operating Officer of TECO Energy. Mr. Bennett is also President and CEO of Emera US Holdings Inc., a holding company for Emera's U.S. assets. Previously he was President and Chief Executive Officer of Emera U.S. Inc., a wholly owned subsidiary of Emera responsible for leading the integration of TECO Energy.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
December 31, 2014	143.78	$ 2,016.4
Issuance of common stock (1)	1.25	53.7
Issued for cash under Purchase Plans at market rate	2.10	88.3
Discount on shares purchased under Dividend Reinvestment Plan	-	(4.1)
Options exercised under senior management stock option plan	0.08	2.3
Employee Share Purchase Plan	-	0.9
December 31, 2015	147.21	$ 2,157.5
Issuance of common stock (1)	0.06	2.9
Issued for cash under Purchase Plans at market rate	1.10	50.2
Discount on shares purchased under Dividend Reinvestment Plan	-	(2.3)
Options exercised under senior management stock option plan	0.54	15.1
Employee Share Purchase Plan	-	0.5
June 30, 2016	**148.91**	**$ 2,223.9**

(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.

As at August 3, 2016, the amount of issued and outstanding common shares was 199.4 million.
The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended June 30, 2016 was 149.7 million (2015 – 145.4 million) and for the six months ended June 30, 2016 was 149.2 million (2015 – 145.2 million).

NSPI

Overview

NSPI is a fully-integrated regulated electric utility with assets of approximately $4.6 billion. It is the primary electricity supplier in Nova Scotia providing electricity generation, transmission and distribution services to approximately 507,000 customers. NSPI's target regulated return on equity ("ROE") range is currently 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.

Review of 2016

NSPI Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Operating revenues – regulated	**$ 314.8**	$ 327.4	**$ 712.3**	$ 773.9
Regulated fuel for generation and purchased power (1)	**101.0**	110.6	**242.5**	300.0
Regulated fuel adjustment mechanism and fixed cost deferrals	**24.0**	22.7	**41.6**	15.5
Operating, maintenance and general	**68.1**	76.0	**155.5**	155.6
Provincial grants and taxes	**9.8**	9.6	**19.5**	19.2
Depreciation and amortization	**48.8**	51.2	**97.2**	102.7
Total operating expenses	**251.7**	270.1	**556.3**	593.0
Income from operations	**63.1**	57.3	**156.0**	180.9
Other expenses, net	**0.6**	0.2	**1.9**	4.0
Interest expense, net	**31.1**	30.7	**62.1**	59.5
Income before provision for income taxes	**31.4**	26.4	**92.0**	117.4
Income tax expense (recovery)	**3.0**	7.5	**11.1**	28.5
Net income of Nova Scotia Power Inc.	**28.4**	18.9	**80.9**	88.9
Preferred stock dividends	**-**	2.0	**-**	4.0
Contribution to consolidated net income	**$ 28.4**	$ 16.9	**$ 80.9**	$ 84.9
Contribution to consolidated earnings per common share	**$ 0.19**	$ 0.12	**$ 0.54**	$ 0.58
EBITDA	**$ 111.3**	$ 108.3	**$ 251.3**	$ 279.6

(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 $11.5 million to $28.4 million in Q2 2016 compared to $16.9 million in Q2 2015. Year-to-date, NSPI's contribution to consolidated net income decreased $4.0 million to $80.9 million in 2016 compared to $84.9 million in 2015.

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended June 30	Six months ended June 30
Contribution to consolidated net income – 2015	**$ 16.9**	**$ 84.9**
Decreased electric margin (see Electric Margin section below for explanation)	(1.8)	(21.3)
Decreased fixed cost deferrals primarily due to a 2015 demand side management ("DSM") regulatory deferral, partially offset by a reduction in the amount of non-fuel revenues deferred	(1.9)	(7.5)
Decreased operating, maintenance and general ("OM&G") expenses quarter-over-quarter primarily due to lower DSM program costs, higher administrative overhead credits, lower pension expense and consulting costs, partially offset by higher storm costs; decreased OM&G expenses year-over-year is primarily due to higher storm and maintenance costs, partially offset by lower DSM program costs and lower pension expense	7.9	0.1
Decreased depreciation and amortization primarily due to lower regulatory amortization as a result of a 2012 deferral being fully amortized in 2015 partially offset by increased depreciation associated with increased property, plant and equipment	2.4	5.5
Decreased income tax expense primarily due to increased accelerated tax deductions related to property, plant and equipment and 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; year-over-year decrease is also due to decreased income before provision for income taxes	4.5	17.4
Other (1)	0.4	1.8
Contribution to consolidated net income – 2016	**$ 28.4**	**$ 80.9**

(1) Amounts exclude variances included in the calculation of electric margin.

Operating Revenues – Regulated

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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Electric revenues	**$ 308.1**	$ 319.6	**$ 699.8**	$ 759.6
Other revenues	**6.7**	7.8	**12.5**	14.3
Operating revenues – regulated	**$ 314.8**	$ 327.4	**$ 712.3**	$ 773.9

Electric Revenues

NSPI's electric revenue is affected by UARB approved rates 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.

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:

Q2 Electric Sales Volumes
Gigawatt hours ("GWh")

	2016	2015	2014
Residential	**967**	1,020	932
Commercial	**729**	725	719
Industrial	**590**	600	625
Other	**65**	74	77
Total	**2,351**	2,419	2,353

YTD Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**2,398**	2,609	2,500
Commercial	**1,569**	1,644	1,602
Industrial	**1,168**	1,202	1,226
Other	**144**	185	167
Total	**5,279**	5,640	5,495

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

Q2 Electric Revenues
millions of Canadian dollars

	2016	2015	2014
Residential	**$ 155.6**	$ 163.3	$ 144.7
Commercial	**94.8**	95.5	90.9
Industrial	**48.1**	49.1	53.4
Other	**9.6**	11.7	12.4
Total	**$ 308.1**	$ 319.6	$ 301.4

YTD Electric Revenues
millions of Canadian dollars

	2016	2015	2014
Residential	**$ 379.0**	$ 411.5	$ 377.5
Commercial	**204.0**	214.9	200.0
Industrial	**96.2**	107.0	109.2
Other	**20.6**	26.2	25.7
Total	**$ 699.8**	$ 759.6	$ 712.4

Electric revenues decreased $11.5 million to $308.1 million in Q2 2016 compared to $319.6 million in Q2 2015. Year-to-date, electric revenues decreased $59.8 million to $699.8 million in 2016 from $759.6 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 June 30	Six months ended June 30
Electric revenues – 2015	**$ 319.6**	**$ 759.6**
Decreased electricity pricing effective January 1, 2016	(2.7)	(6.5)
Decreased residential sales volume, in part due to weather in Q1	(6.3)	(29.0)
Change in commercial sales volume, primarily due to load	0.4	(8.4)
Decreased industrial sales volume	(2.9)	(12.5)
Other	-	(3.4)
Electric revenues – 2016	**$ 308.1**	**$ 699.8**

Regulated Fuel for Generation and Purchased Power

Q2 Production Volumes
GWh

	2016	2015	2014
Coal and petroleum coke ("petcoke")	**1,323**	1,193	1,459
Natural gas	**300**	448	433
Oil	**12**	6	5
Purchased power – other	**94**	110	47
Total non-renewables	**1,729**	1,757	1,944
Wind and hydro – renewables	**312**	403	362
Biomass – renewables	**36**	55	48
Purchased power – renewables	**355**	280	172
Total renewables	**703**	738	582
Total production volumes	**2,432**	2,495	2,526

YTD Production Volumes
GWh

	2016	2015	2014
Coal and petcoke	**3,011**	3,441	3,732
Natural gas	**585**	612	612
Oil	**153**	255	140
Purchased power – other	**189**	197	94
Total non-renewables	**3,938**	4,505	4,578
Wind and hydro – renewables	**718**	787	778
Biomass – renewables	**106**	107	101
Purchased power – renewables	**824**	597	426
Total renewables	**1,648**	1,491	1,305
Total production volumes	**5,586**	5,996	5,883

Q2 Average Fuel Costs

	2016	2015	2014
Dollars per MWh produced	**$ 42**	$ 44	$ 43

YTD Average Fuel Costs

	2016	2015	2014
Dollars per MWh produced	**$ 43**	$ 50	$ 48

Average unit fuel costs decreased in both Q2 and year-to-date in 2016 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 Independent Power Producers ("IPP") including Community Feed-in Tariff ("COMFIT") participants), 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.

Historically, coal and petcoke have the lowest per unit fuel cost, after NSPI-owned regulated hydro and wind, which have no fuel cost component. Purchased power, natural gas, oil and biomass 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 wind, which typically has a higher cost per MWh.

Regulated fuel for generation and purchased power decreased $9.6 million to $101.0 million in Q2 2016 compared to $110.6 million in Q2 2015. Year-to-date, regulated fuel for generation and purchased power decreased $57.5 million to $242.5 million in 2016 compared to $300.0 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 June 30		Six months ended June 30
Regulated fuel for generation and purchased power – 2015	**$**	**110.6**	**$**	**300.0**
Change in generation mix		(1.9)		6.7
Decreased commodity prices		(9.0)		(45.1)
Decreased sales volumes		(3.1)		(21.1)
Other		4.4		2.0
Regulated fuel for generation and purchased power – 2016	**$**	**101.0**	**$**	**242.5**

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 to a maximum of $5.0 million. The incentive was suspended from 2012 to 2015, as a result of an UARB approved settlement agreements and is in effect for 2016. The incentive is suspended as part of the *Electricity Plan Act* from 2017 to 2019.

In December 2015, the UARB approved NSPI's 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's filings. Approved customer rates reset the base cost of fuel rate for 2016 and seek to recover $12.9 million of prior years' unrecovered Fuel Costs in 2016. Recovery of those 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. 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 subsequent to 2019. Differences between actual Fuel Costs and amounts recovered from customers during 2016 are being deferred to a FAM regulatory asset or liability and will be recovered from or returned to customers in the 2017 to 2019 period.

The *Electricity Plan Act* further directed NSPI to apply 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. 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 and used in the 2017 to 2019 period. The exception to this direction is application of a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would otherwise have been required. This amount totals $3.8 million.

For the three months ended June 30, 2016, NSPI applied $3.8 million (year-to-date $7.6 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*.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. The audit for fiscal 2014 and 2015 is currently underway.

The impact of the FAM included in the Statements of Income includes the effect of fuel Costs in both the current and proceeding 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 regulated fuel adjustment mechanism and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income. Details of the FAM regulatory asset (liability), classified in "Regulatory assets" or "Regulatory liabilities" on the Consolidated Balance Sheets, are summarized in the following table:

millions of Canadian dollars		**2016**
FAM regulatory liability – Balance as at January 1	**$**	**(28.3)**
Under (over) recovery of current period Fuel Costs		(27.4)
Rebate to (recovery from) customers of prior years' Fuel Costs		(6.6)
Interest on FAM balance		(1.9)
Application of non-fuel revenues associated with tax benefits		(7.6)
FAM regulatory liability – Balance as at June 30	**$**	**(71.8)**

Electric 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. Consequently, Fuel Costs and related revenues (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 $5.0 million.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to NSPI'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 DSM activities have the largest effect on non-fuel electric revenues and electric margin. Changes in industrial load, which are generally due to economic conditions, 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 June 30			Six months ended June 30
		2016	2015	**2016**	2015
Fuel electric revenues – current year	**$**	**118.6**	$ 117.9	**$ 270.6**	$ 283.6
Fuel electric revenues – recovery of preceding years		**2.8**	12.9	**6.6**	31.1
Non-fuel electric revenues		**186.7**	188.8	**422.6**	444.9
Other revenues		**6.7**	7.8	**12.5**	14.3
Operating revenues	**$**	**314.8**	$ 327.4	**$ 712.3**	$ 773.9

Electric margin is summarized in the following table:

Fuel electric revenues – current year	**$**	**118.6**	$ 117.9	**$ 270.6**	$ 283.6
Fuel electric revenues – recovery of preceding years		**2.8**	12.9	**6.6**	31.1
Total fuel electric revenues		**121.4**	130.8	**277.2**	314.7
Regulated fuel for generation and purchased power		**(101.0)**	(110.6)	**(242.5)**	(300.0)
Regulated fuel adjustment mechanism		**(20.2)**	(20.8)	**(34.0)**	(15.4)
Fuel-related foreign exchange gain (loss) (1)		**0.1**	0.6	**0.3**	0.7
Net fuel revenue (expense) (2)		**0.3**	-	**1.0**	-
Non-fuel electric revenues		**186.7**	188.8	**422.6**	444.9
Electric margin	**$**	**187.0**	$ 188.8	**$ 423.6**	$ 444.9

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

NSPI’s electric margin decreased $1.8 million to $187.0 million in Q2 2016 compared to $188.8 million in Q2 2015 and year-to-date decreased $21.3 million to $423.6 million in 2016 compared to $444.9 million during the same period in 2015 primarily due to decreased residential and commercial sales reflecting warmer weather in Q1 2016 and decreased load.

Q2 Average Electric Margin/MWh				
		2016	2015	2014
Dollars per MWh sold	**$**	**80**	$ 78	$ 78

YTD Average Electric Margin/MWh				
		2016	2015	2014
Dollars per MWh sold	**$**	**80**	$ 79	$ 79

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 GAAP, 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Income from operations	**$ 63.1**	$ 57.3	**$ 156.0**	$ 180.9
Less:				
Fuel electric revenues	**121.4**	130.8	**277.2**	314.7
Other revenues	**6.7**	7.8	**12.5**	14.3
Add back:				
Regulated fuel for generation and purchased power	**101.0**	110.6	**242.5**	300.0
Operating, maintenance and general	**68.1**	76.0	**155.5**	155.6
Provincial grants and taxes	**9.8**	9.6	**19.5**	19.2
Depreciation and amortization	**48.8**	51.2	**97.2**	102.7
Regulated fuel adjustment and fixed cost deferrals	**24.0**	22.7	**41.6**	15.5
Other fuel costs	**0.3**	-	**1.0**	-
Electric margin	$ **187.0**	**$** 188.8	**$ 423.6**	**$** 444.9

EMERA MAINE

Overview

Emera Maine is a transmission and distribution electric utility with assets of approximately $1.1 billion, serving 159,000 customers in the State of Maine in the United States.

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 operates under a cost-of-service regulatory structure. 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Operating revenues – regulated	**$ 50.8**	$ 53.5	**$ 108.5**	$ 109.3
Operating revenues – non-regulated	**0.1**	0.4	**0.3**	0.4
Total operating revenues	**50.9**	53.9	**108.8**	109.7
Regulated fuel for generation and purchased power	**6.8**	5.5	**14.6**	13.2
Transmission pool expense (1)	**6.0**	5.8	**12.3**	11.9
Operating, maintenance and general	**10.7**	9.4	**26.6**	22.6
Provincial, state and municipal taxes	**3.2**	3.3	**6.8**	6.8
Depreciation and amortization	**9.6**	10.2	**20.3**	19.0
Total operating expenses	**36.3**	34.2	**80.6**	73.5
Income from operations	**14.6**	19.7	**28.2**	36.2
Other income (expenses), net	**0.5**	0.9	**0.7**	2.0
Interest expense, net	**3.7**	3.4	**7.3**	6.8
Income before provision for income taxes	**11.4**	17.2	**21.6**	31.4
Income tax expense (recovery)	**3.9**	6.0	**7.3**	10.9
Contribution to consolidated net income – USD	**$ 7.5**	$ 11.2	**$ 14.3**	$ 20.5
Contribution to consolidated net income – CAD	**$ 9.7**	$ 13.7	**$ 19.0**	$ 25.2
Contribution to consolidated earnings per common share – CAD	**$ 0.06**	$ 0.09	**$ 0.13**	$ 0.17
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.29**	$ 1.22	**$ 1.33**	$ 1.23
EBITDA – USD	**$ 24.7**	$ 30.8	**$ 49.2**	$ 57.2
EBITDA – CAD	**$ 31.6**	$ 37.8	**$ 65.1**	$ 70.6

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

Emera Maine's USD contribution to consolidated net income decreased by $3.7 million to $7.5 million in Q2 2016 compared to $11.2 million in Q2 2015. Year-to-date, Emera Maine's USD contribution to consolidated net income decreased by $6.2 million to $14.3 million in 2016 compared to $20.5 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 June 30		Six months ended June 30
Contribution to consolidated net income – 2015	**$**	**11.2**	**$**	**20.5**
Decreased operating revenues - regulated (see Operating Revenues - Regulated Section below)		(2.7)		(0.8)
Increased regulated fuel for generation and purchased power due to changes in long-term purchased power contracts		(1.3)		(1.4)
Increased OM&G quarter-over-quarter due to increased payroll, benefit and storm costs; year-over-year increase due to decreased capitalized construction overheads as a result of lower capital spending and storm costs		(1.3)		(4.0)
Decreased depreciation and amortization quarter-over-quarter primarily due to changes in stranded cost regulatory amortization; increased year-over-year primarily due to higher plant in service, offset by changes in stranded cost regulatory amortization		0.6		(1.3)
Decreased other income (expenses), net primarily due to lower AFUDC equity as a result of lower construction work in progress		(0.4)		(1.3)
Decreased income tax expense primarily due to decreased income before provision for income taxes		2.1		3.6
Other		(0.7)		(1.0)
Contribution to consolidated net income – 2016	**$**	**7.5**	**$**	**14.3**

Emera Maine’s CAD contribution to consolidated net income decreased by $4.0 million to $9.7 million in Q2 2016 from $13.7 million in Q2 2015 and year-to-date decreased by $6.2 million to $19.0 million in 2016 from $25.2 million during the same period in 2015. The impact of a stronger USD increased CAD earnings by $0.5 million for the three months ended June 30, 2016 and by $1.4 million for the six months ended June 30, 2016.

Operating Revenues – Regulated

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

Q2 Operating Revenues – Regulated
millions of US dollars

		2016		2015
Electric revenues	**$**	**36.9**	$	39.9
Transmission pool revenues		**11.5**		10.8
Resale of purchased power		**2.4**		2.8
Operating revenues – regulated	**$**	**50.8**	$	53.5

YTD Operating Revenues – Regulated
millions of US dollars

		2016		2015
Electric revenues	**$**	**78.6**	$	79.9
Transmission pool revenues		**23.1**		23.0
Resale of purchased power		**6.8**		6.4
Operating revenues – regulated	**$**	**108.5**	$	109.3

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.

Q2 Electric Sales Volumes

GWh	2016	2015	2014
Residential	**176**	176	178
Commercial	**183**	175	183
Industrial	**85**	109	103
Other	**4**	3	4
Total	**448**	463	468

YTD Electric Sales Volumes

GWh	2016	2015	2014
Residential	**394**	412	410
Commercial	**381**	381	389
Industrial	**166**	212	209
Other	**8**	7	7
Total	**949**	1,012	1,015

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

Q2 Electric Revenues
millions of US dollars

		2016	2015	2014
Residential	**$**	**17.1**	$ 16.6	$ 16.6
Commercial		**14.2**	13.4	13.2
Industrial		**2.7**	3.4	2.6
Other (1)		**2.9**	6.5	1.8
Total	**$**	**36.9**	$ 39.9	$ 34.2

YTD Electric Revenues
millions of US dollars

		2016	2015	2014
Residential	**$**	**37.8**	$ 38.3	$ 37.1
Commercial		**29.0**	27.5	28.3
Industrial		**5.9**	6.8	7.3
Other (1)		**5.9**	7.3	3.9
Total	**$**	**78.6**	$ 79.9	$ 76.6

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

Electric revenues decreased $3.0 million to $36.9 million in Q2 2016 compared to $39.9 million in Q2 2015. Year-to-date, electric revenues decreased $1.3 million to $78.6 million in 2016 compared to $79.9 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 June 30		Six months ended June 30
Electric revenues – 2015	**$**	**39.9**	**$**	**79.9**
Decreased sales volumes primarily due to weather and loss of load associated with the closing of two large industrial customers in December 2015		(1.2)		(4.9)
Increased primarily due to rate changes		1.5		5.1
Increased due to changes in FERC transmission rate refund reserves		0.1		1.3
Increased transmission revenue adjustments		(3.4)		(2.8)
Electric revenues – 2016	**$**	**36.9**	**$**	**78.6**

Q2 Average Electric Revenue / MWh

US dollars		**2016**	2015	2014
Dollars per MWh	**$**	**82**	$ 86	$ 73

YTD Average Electric Revenue / MWh

US dollars		**2016**	2015	2014
Dollars per MWh	**$**	**83**	$ 79	$ 75

The decrease in the average electric revenue per MWh in Q2 2016 compared to Q2 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" and transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

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

For the millions of US dollars	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Transmission pool revenues	**$ 11.5**	$ 10.8	**$ 23.1**	$ 23.0
Transmission pool expenses	**6.0**	5.8	**12.3**	11.9
Net transmission pool revenues	**$ 5.5**	$ 5.0	**$ 10.8**	$ 11.1

Emera Maine's net transmission pool revenues increased $0.5 million to $5.5 million in Q2 2016 compared to $5.0 million in Q2 2015 and year-to-date decreased $0.3 million to $10.8 million in 2016 compared to $11.1 million in 2015. This was primarily due to changes in the level of investment in regionally funded transmission assets and the impact of weather.

EMERA CARIBBEAN

Overview

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 which is regulated by the Government of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2016

Emera Caribbean Net Income

For the millions of US dollars (except per share amounts)		Three months ended June 30				Six months ended June 30
		2016		2015		**2016**		2015
Operating revenues – regulated	**$**	**78.4**	$	86.7	**$**	**149.4**	$	169.8
Operating revenues – non-regulated		**-**		2.0		**-**		3.9
Total operating revenues		**78.4**		88.7		**149.4**		173.7
Regulated fuel for generation and purchased power		**30.5**		39.9		**57.2**		79.0
Non-regulated direct costs		**-**		1.8		**-**		3.6
Operating, maintenance and general		**22.9**		31.4		**44.5**		54.2
Property taxes (1)		**0.6**		0.5		**1.2**		0.9
Depreciation and amortization		**9.2**		8.5		**18.6**		17.1
Total operating expenses		**63.2**		82.1		**121.5**		154.8
Income from operations		**15.2**		6.6		**27.9**		18.9
Income from equity investment		**0.7**		0.7		**1.1**		1.2
Other income (expenses), net		**41.7**		0.1		**42.0**		1.6
Interest expense, net		**2.7**		2.6		**5.5**		5.3
Income before provision for income taxes		**54.9**		4.8		**65.5**		16.4
Income tax expense (recovery)		**8.3**		(1.2)		**9.3**		(0.2)
Net income		**46.6**		6.0		**56.2**		16.6
Non-controlling interest in subsidiaries		**1.6**		2.1		**2.8**		4.3
Preferred stock dividends (2)		**-**		-		**1.3**		1.3
Contribution to consolidated net income – USD	**$**	**45.0**	$	3.9	**$**	**52.1**	$	11.0
Contribution to consolidated net income – CAD	**$**	**58.1**	$	4.8	**$**	**67.9**	$	13.6
Contribution to consolidated earnings per common share – CAD	**$**	**0.39**	$	0.03	**$**	**0.46**	$	0.09
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.29**	$	1.23	**$**	**1.30**	$	1.24
EBITDA – USD	**$**	**66.8**	$	15.9	**$**	**89.6**	$	38.8
EBITDA – CAD	**$**	**86.2**	$	19.7	**$**	**117.7**	$	48.0

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

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

Emera Caribbean's USD contribution to consolidated net income increased by $41.1 million to $45.0 million in Q2 2016 compared to $3.9 million in Q2 2015. Year-to-date, Emera Caribbean's USD contribution to consolidated net income increased by $41.1 million to $52.1 million in 2016 compared to $11.0 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 June 30		Six months ended June 30
Contribution to consolidated net income – 2015	**$**	**3.9**	$	**11.0**
Increased Electric Margin – see Electric Margin section		1.6		2.0
Decreased OM&G primarily due to restructuring payroll savings at BLPC and operational cost savings at GBPC		8.5		9.7
Increased other income primarily due to a pre-tax gain recognized on the SIF regulatory liability		41.6		40.4
Increased income tax expense primarily due to a gain recognized on the SIF regulatory liability		(9.5)		(9.5)
Other		(1.1)		(1.5)
Contribution to consolidated net income – 2016	**$**	**45.0**	$	**52.1**

Emera Caribbean's CAD contribution to consolidated net income increased by $53.3 million to $58.1 million in Q2 2016 compared to $4.8 million in Q2 2015 and year-over-year increased by $54.3 million to $67.9 million in 2016 compared to $13.6 million during the same period in 2015. The impact of a stronger USD increased CAD earnings by $2.7 million for the three months ended June 30, 2016 and $3.1 million for the six months ended June 30, 2016.

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 $22.0 million USD. As a result, Emera recorded a pre-tax gain of $41.2 million USD and an after-tax gain of $33.7 million USD. Absent this gain, the Emera Caribbean contribution to the consolidated net income in Q2 2016 was $11.3 million USD ($14.7 million CAD) and year-to-date in 2016 was $18.4 million USD ($23.5 million CAD).

Operating Revenues – Regulated

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

Q2 Operating Revenues – Regulated
millions of US dollars

		2016		2015
Electric revenues – base rates	**$**	**47.6**	$	46.3
Fuel charge		**29.9**		39.2
Total electric revenues		**77.5**		85.5
Other revenues		**0.9**		1.2
Operating revenues – regulated	**$**	**78.4**	$	86.7

YTD Operating Revenues – Regulated
millions of US dollars

		2016		2015
Electric revenues – base rates	**$**	**91.6**	$	89.9
Fuel charge		**56.0**		77.8
Total electric revenues		**147.6**		167.7
Other revenues		**1.8**		2.1
Operating revenues – regulated	**$**	**149.4**	$	169.8

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.

Q2 Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**117**	111	107
Commercial	**195**	190	189
Industrial	**24**	27	26
Other	**5**	7	6
Total	**341**	335	328

YTD Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**226**	216	211
Commercial	**374**	369	366
Industrial	**47**	54	50
Other	**11**	13	13
Total	**658**	652	640

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

Q2 Electric Revenues
millions of US dollars

		2016		2015		2014
Residential	**$**	**25.3**	$	27.1	$	37.8
Commercial		**44.3**		49.7		65.7
Industrial		**6.3**		7.1		4.6
Other		**1.6**		1.6		1.9
Total	**$**	**77.5**	$	85.5	$	110.0

YTD Electric Revenues
millions of US dollars

		2016		2015		2014
Residential	**$**	**47.8**	$	53.0	$	69.0
Commercial		**83.6**		95.8		124.2
Industrial		**13.1**		15.7		13.0
Other		**3.1**		3.2		3.6
Total	**$**	**147.6**	$	167.7	$	209.8

Electric revenues decreased $8.0 million to $77.5 million in Q2 2016 compared to $85.5 million in Q2 2015. Year-to-date, electric revenues decreased $20.1 million to $147.6 million in 2016 compared to $167.7 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 June 30		Six months ended June 30
Electric revenues – 2015	**$**	**85.5**	**$**	**167.7**
Decreased fuel charge revenues primarily due to lower fuel prices		(9.3)		(21.8)
Increased due to higher sales volumes at BLPC due to weather		1.3		1.7
Electric revenues – 2016	**$**	**77.5**	**$**	**147.6**

Q2 Average Electric Revenue/MWh						
US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**227**	$	255	$	335

YTD Average Electric Revenue/MWh						
US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**224**	$	257	$	328

The change in average electric revenue per MWh in Q2 2016 compared to Q2 2015, and year-to-date in 2016 compared to the same periods in 2015 was the result of the decreased fuel charge primarily due to lower fuel prices.

Electric 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 June 30				Six months ended June 30
		2016		2015		**2016**		2015
Operating revenues – regulated	**$**	**78.4**	$	86.7	**$**	**149.4**	$	169.8
Less: Other revenues		**(0.9)**		(1.2)		**(1.8)**		(2.1)
Total electric revenues	**$**	**77.5**	$	85.5	**$**	**147.6**	$	167.7
Total electric revenues are broken down as follows:								
Electric revenues – base rate	**$**	**47.6**	$	46.3	**$**	**91.6**	$	89.9
Fuel charge		**29.9**		39.2		**56.0**		77.8
Total electric revenues		**77.5**		85.5		**147.6**		167.7
Regulated fuel for generation and purchased power		**30.5**		39.9		**57.2**		79.0
Regulatory amortization (1)		**0.5**		0.7		**1.1**		1.4
Electric margin	**$**	**46.5**	$	44.9	**$**	**89.3**	$	87.3

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

Emera Caribbean's electric margin increased $1.6 million to $46.5 million in Q2 2016 compared to $44.9 million in Q2 2015 and year-to-date increased by $2.0 million to $89.3 million in 2016 compared to $87.3 million in 2015 due to increased sales volumes at BLPC.

Q2 Average Electric Margin / MWh						
US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**136**	$	134	$	136

YTD Average Electric Margin / MWh						
US Dollars		**2016**		2015		2014
Dollars per MWh	**$**	**136**	$	134	$	135

Emera Caribbean average electric margin is consistent period over period.

Regulated Fuel for Generation and Purchased Power

Q2 Production Volumes
GWh

	2016	2015	2014
Oil	**360**	358	350
Hydro	**9**	7	8
Total	**369**	365	358

YTD Production Volumes
GWh

	2016	2015	2014
Oil	**697**	693	680
Hydro	**18**	14	16
Total	**715**	707	696

Regulated fuel for generation and purchased power decreased $9.4 million to $30.5 million in Q2 2016 compared to $39.9 million in Q2 2015. Year-to-date, regulated fuel for generation and purchased power decreased $21.8 million to $57.2 million in 2016 compared to $79.0 million during the same period in 2015 primarily due to lower fuel prices.

Q2 Average Fuel Costs/MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 83**	$ 109	$ 180

YTD Average Fuel Costs/MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 80**	$ 112	176

The decrease in the average fuel costs in Q2 2016 and year-to-date compared to the same periods in 2015 was the result of lower fuel 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Income from operations	**$ 15.2**	$ 6.6	**$ 27.9**	$ 18.9
Less:				
Operating revenues – non-regulated	**-**	2.0	**-**	3.9
Other revenue	**0.9**	1.2	**1.8**	2.1
Add back:				
Non-regulated direct costs	**-**	1.8	**-**	3.6
Operating, maintenance and general	**22.9**	31.4	**44.5**	54.2
Property taxes	**0.6**	0.5	**1.2**	0.9
Depreciation and amortization (1)	**8.7**	7.8	**17.5**	15.7
Electric margin	**$ 46.5**	$ **44.9**	**$ 89.3**	$ **87.3**

(1) Depreciation and amortization excludes $0.5 million of regulatory amortization in Q2 2016 (2015 – $0.7 million) and $1.1 million YTD in 2016 (2015 – $1.4 million).

PIPELINES

Overview

Pipelines is comprised of Emera's wholly owned Brunswick Pipeline and the Company's 12.9 per cent interest in the M&NP.

- Brunswick Pipeline is a 145-kilometre pipeline delivering re-gasified natural gas from the Canaport™ liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States for Repsol Energy Canada under a 25-year firm service agreement which expires in 2034. The NEB, which regulates Brunswick Pipeline, has classified it as a Group II pipeline. The agreement is accounted for as a direct financing lease.

- M&NP is a 1,400-kilometre transmission pipeline built to transport natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States. The investment in M&NP is accounted for on the equity basis.

Mark-to-Market Adjustments

Pipelines' "Interest expense, net" and "Income tax expense (recovery)" are affected by mark-to-market adjustments on an interest rate swap. Pipelines' income table below shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

Review of 2016

Pipelines' Adjusted Net Income

For the millions of Canadian dollars (except per share amounts)		Three months ended June 30		Six months ended June 30	
		2016	2015	**2016**	2015
Operating revenues – regulated	**$**	**12.2**	$ 13.0	**$ 25.1**	$ 26.1
Operating maintenance and general		**0.1**	-	**0.2**	0.2
Accretion (1)		**0.1**	0.1	**0.2**	0.2
Income from equity investment		**5.1**	4.8	**11.0**	10.7
Other income (expenses), net		**-**	(0.2)	**(0.2)**	0.5
Interest expense, net (2)		**5.8**	5.5	**11.5**	11.7
Adjusted income before provision for income taxes		**11.3**	12.0	**24.0**	25.2
Income tax expense (recovery) (3)		**3.0**	2.7	**6.0**	6.0
Adjusted contribution to consolidated net income	**$**	**8.3**	$ 9.3	**$ 18.0**	$ 19.2
After-tax derivative mark-to-market gain (loss)	**$**	**0.2**	$ (1.4)	**$ (0.1)**	$ (1.4)
Contribution to consolidated net income	**$**	**8.5**	$ 7.9	**$ 17.9**	$ 17.8
Adjusted contribution to consolidated earnings per common share	**$**	**0.06**	$ 0.06	**$ 0.12**	$ 0.13
Contribution to consolidated earnings per common share	**$**	**0.06**	$ 0.05	**$ 0.12**	$ 0.12
Adjusted EBITDA	**$**	**17.2**	$ 17.6	**$ 35.7**	$ 37.1

(1) Accretion related to reclamation of the pipeline is included in "Depreciation and amortization" on the Consolidated Statements of Income.
(2) Interest expense, net excludes a pre-tax mark-to-market gain of $0.2 million in Q2 2016 (2015 - $1.9 million loss) and a loss of $0.1 million YTD in 2016 (2015 - $1.9 million loss).
(3) Income tax expense (recovery) excludes a $0.5 million recovery related to mark-to-market losses in Q2 2015 and YTD 2015.

Pipelines' contribution to consolidated net income in 2016 is consistent with 2015.

EMERA ENERGY

Overview

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.

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 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.

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, specifically 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.

Review of 2016

Emera Energy Adjusted Contribution to Consolidated Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Marketing and trading margin (1)	**$ (14.1)**	$ 2.9	**$ 32.8**	$ 41.7
Electricity sales (2)	**77.0**	59.7	**257.1**	310.6
Total operating revenues – non-regulated	**62.9**	62.6	**289.9**	352.3
Non-regulated fuel for generation and purchased power (3)(4)	**74.7**	34.8	**188.8**	194.7
Operating, maintenance and general	**18.4**	17.5	**43.7**	37.6
Provincial, state and municipal taxes	**1.9**	1.5	**2.8**	2.9
Depreciation and amortization	**10.6**	9.7	**21.5**	19.0
Total operating expenses	**105.6**	63.5	**256.8**	254.2
Adjusted income (loss) from operations	**(42.7)**	(0.9)	**33.1**	98.1
Income (loss) from equity investments (5)	**3.3**	11.8	**7.1**	15.8
Other income (expenses), net	**0.2**	(0.3)	**(2.4)**	21.9
Interest expense, net	**5.8**	5.8	**12.0**	6.8
Adjusted income (loss) before provision for income taxes	**(45.0)**	4.8	**25.8**	129.0
Income tax expense (recovery) (6)	**(16.3)**	1.4	**6.6**	49.2
Adjusted contribution to consolidated net income (loss)	**$ (28.7)**	$ 3.4	**$ 19.2**	$ 79.8
After-tax derivative mark-to-market gain (loss)	**$ (34.8)**	$ (36.6)	**$ 10.7**	$ (48.1)
Contribution to consolidated net income	**$ (63.5)**	$ (33.2)	**$ 29.9**	$ 31.7
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.19)**	$ 0.02	**$ 0.13**	$ 0.55
Contribution to consolidated earnings per common share – basic	**$ (0.42)**	$ (0.23)	**$ 0.20**	$ 0.22
Adjusted EBITDA	**$ (28.6)**	$ 20.3	**$ 59.3**	$ 154.8

(1) Marketing and trading margin excludes a pre-tax mark-to-market loss of $60.5 million in Q2 2016 (2015 - $57.8 million loss) and a gain of $11.8 million YTD in 2016 (2015 - $43.9 million loss)

(2) Electricity sales excludes a pre-tax mark-to-market gain of $5.2 million in Q2 2016 (2015 - $8.0 million gain) and a loss of $3.1 million YTD in 2016 (2015 - $37.8 million loss)

3) Non-regulated fuel for generation and purchased power includes $3.5 million pre-tax ($2.1 million after-tax) of state fuel taxes related to Q1 2016.

(4) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $4.8 million in Q2 2016 (2015 - $3.5 million loss) and a gain of $7.6 million YTD in 2016 (2015 - $3.4 million gain)

(5) Income from equity investments excludes a pre-tax mark-to-market gain of $2.4 million in Q2 2016 (2015 - $0.7 million gain) and a gain/loss of nil YTD in 2016 (2015 - $4.2 million gain)

(6) Income tax expense (recovery) excludes a $13.3 million recovery relating to mark-to-market losses in Q2 2016 (2015 - $16.0 million recovery) and a $5.6 million expense relating to mark-to-market gains YTD in 2016 (2015 - $26.0 million recovery)

Emera Energy's contribution to consolidated net income decreased by $30.3 million to $(63.5) million in Q2 2016 compared to $(33.2) million in Q2 2015. Year-to-date, contribution to consolidated net income decreased $1.8 million to $29.9 million in 2016 compared to $31.7 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 June 30	Six months ended June 30
Contribution to consolidated net income – 2015	**$ (33.2)**	**$ 31.7**
Decreased marketing and trading margin in Q2, reflecting a $12.6 million increase in margin from gas sales, which was more than offset by an increase in short-term fixed cost commitments for transportation and storage; mitigated year-to-date by higher margins in Q1 primarily due to increased volumes	(17.0)	(8.9)
Increased electricity sales quarter-over-quarter primarily due to fewer planned outage hours at the Bridgeport Energy facility in 2016; year-over-year these increases were offset by lower hedged and market power prices at the New England Gas Generating Facilities, and lower market prices at Bayside Power, partially offset by a stronger USD	17.3	(53.5)
Increased non-regulated fuel for generation and purchased power quarter-over-quarter primarily due to the recognition of $19.9 million in state fuel taxes for 2013 through March 2016; and fewer planned outage hours at the Bridgeport Energy facility in 2016. Year-over-year these increases were offset by lower hedged and market commodity prices at the New England Gas Generating Facilities, and lower market commodity prices at Bayside Power, partially offset by a stronger USD	(39.9)	5.9
Increased OM&G year-over-year primarily due to a stronger USD, higher outage costs at the Maritime Canada Facilities, and increased corporate costs, partially offset by decreased performance-based compensation resulting from decreased marketing and trading margin	(0.9)	(6.1)
Decreased income from equity investments - See Equity Investments section below	(8.5)	(8.7)
Decreased other income year-over-year primarily due to a gain on the sale of NWP in 2015	0.5	(24.3)
Increased interest expense, net year-over-year due to higher interest rates on internal financing	-	(5.2)
Decreased income tax expense primarily due to decreased income before provision for income taxes and changes in the proportion of income earned in higher tax rate foreign jurisdictions	17.7	42.6
Increased mark-to-market, net of tax primarily due to the reversal of 2015 mark-to-market losses and changes in gas and power contract positions, partially offset by amortization of 2015 gas transportation assets	1.8	58.8
Other	(1.3)	(2.4)
Contribution to consolidated net income – 2016	**$ (63.5)**	**$ 29.9**

A significant portion of Emera Energy earnings are exposed to foreign exchange fluctuations thereby affecting CAD dollar contribution to net earnings. The impact of a stronger USD quarter-over-quarter increased the loss in CAD dollars by $2.9 million in Q2 2016 compared to Q2 2015. Year-to-date in 2016 the impact of a stronger USD increased earnings in CAD dollars by $11.1 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Marketing and trading margin	**$ (14.1)**	$ 2.9	**$ 32.8**	$ 41.7
OM&G	**1.6**	2.3	**12.0**	9.8
Other income (expenses), net	**-**	(0.4)	**(3.7)**	3.1
Adjusted EBITDA	**$ (15.7)**	$ 0.2	**$ 17.1**	$ 35.0

Marketing and Trading Margin

Marketing and trading margin decreased $17.0 million to $(14.1) million in Q2 2016 compared to $2.9 million in Q2 2015. Margin from gas sales was $12.6 million higher quarter-over-quarter, despite weaker market conditions, reflecting increased volumes. However, this was more than offset by increased short-term fixed cost commitments for transportation and storage.

Year-to-date, marketing and trading margin decreased $8.9 million to $32.8 million in 2016 compared to $41.7 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 impact of increased short-term transportation and storage costs.

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 June 30
	New England		Maritime Canada		Total	
	2016	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 50.3**	$ 35.1	**$ 13.5**	$ 14.7	**$ 63.8**	$ 49.8
Capacity and other	**13.2**	9.9	**-**	-	**13.2**	9.9
Electricity sales	**$ 63.5**	$ 45.0	**$ 13.5**	$ 14.7	**$ 77.0**	$ 59.7
Non-regulated fuel for generation and purchased power	**59.3**	26.4	**12.8**	6.1	**72.1**	32.5
Non-regulated electric margin	**4.2**	18.6	**0.7**	8.6	**4.9**	27.2
Provincial, state and municipal taxes	**1.2**	1.2	**0.2**	0.1	**1.4**	1.3
OM&G	**10.9**	9.9	**5.7**	4.9	**16.6**	14.8
Other income (expenses), net	**-**	-	**0.2**	0.3	**0.2**	0.3
Adjusted EBITDA	**$ (7.9)**	$ 7.5	**$ (5.0)**	$ 3.9	**$ (12.9)**	$ 11.4

For the millions of Canadian dollars						Six months ended June 30
	New England		Maritime Canada			Total
	2016	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 189.6**	$ 236.4	**$ 41.8**	$ 53.7	**$ 231.4**	$ 290.1
Capacity and other	**25.7**	20.5	**-**	-	**25.7**	20.5
Electricity sales	**$ 215.3**	$ 256.9	**$ 41.8**	$ 53.7	**$ 257.1**	$ 310.6
Non-regulated fuel for generation and purchased power	**153.4**	159.8	**31.1**	34.7	**184.5**	194.5
Non-regulated electric margin	**61.9**	97.1	**10.7**	19.0	**72.6**	116.1
Provincial, state and municipal taxes	**1.9**	2.3	**0.4**	0.4	**2.3**	2.7
OM&G	**19.9**	17.2	**11.2**	9.4	**31.1**	26.6
Other income (expenses), net	**-**	1.3	**1.3**	(1.0)	**1.3**	0.3
Adjusted EBITDA	**$ 40.1**	$ 78.9	**$ 0.4**	$ 8.2	**$ 40.5**	$ 87.1

Adjusted EBITDA decreased $24.3 million to $(12.9) million in Q2 2016 from $11.4 million in Q2 2015; and year-to-date decreased $46.6 million to $40.5 million in 2016 from $87.1 million for the same period in 2015. The New England Gas Generating Facilities performed well in Q2 2016 generating nearly 50.0 per cent more MWs than in Q2 2015 predominately as a result of fewer planned outage hours. The favourable quarter-over-quarter operational and commercial results were fully offset by a $19.9 million charge to cost of fuel to recognize fuel taxes for 2013 through March 2016. Absent this, the New England Gas Generating Facilities would have contributed $12.0 million in EBITDA for the quarter, a $4.5 million increase over Q2 2015, and year-to-date, EBITDA would have been $60.0 million, a decrease of $18.9 million over the same period in 2015. Year-over-year, EBITDA in the New England Gas Generation Facilities also reflects less favourable short-term economic hedges in Q1 2016 compared to Q1 2015. This was partially offset by the stronger USD.

The Maritime Canada Facilities also saw a marginal increase in capacity factor, but this was offset by increased cost of gas at Bayside Power, reflecting the expiry of a long-term favourable gas contract, and its replacement at market rates, which resulted in an $8.9 million reduction in EBITDA quarter-over-quarter; and a $7.8 million reduction year-over-year.

Operating Statistics

For the						Three months ended June 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**1,315**	878	**91.9%**	91.6%	**55.2%**	37.5%
Maritime Canada	**431**	422	**86.4%**	86.8%	**63.2%**	61.8%
Total	**1,746**	1,300	**90.6%**	90.5%	**57.0%**	43.0%

For the						Six months ended June 30
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**2,615**	2,288	**94.0%**	94.8%	**54.9%**	49.2%
Maritime Canada	**949**	905	**91.1%**	93.0%	**69.5%**	66.4%
Total	**3,564**	3,193	**93.4%**	94.4%	**58.2%**	53.1%

(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 increased quarter-over-quarter and year-over-year in 2016 compared to 2015 at the New England Gas Generating Facilities primarily due to fewer planned outage hours in 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 marginally increased compared to prior year.

The New England Gas Generating Facilities sell into price based competitive markets. The primary reason the overall capacity factor is lower for New England Gas Generating Facilities 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Bear Swamp	**$ 3.3**	$ 11.8	**$ 7.1**	$ 13.9
NWP	**-**	-	**-**	1.9
Adjusted income from equity investments	**$ 3.3**	$ 11.8	**$ 7.1**	$ 15.8

Adjusted income from equity investments decreased $8.5 million to $3.3 million in Q2 2016 compared to $11.8 million in Q2 2015. Year-to-date, adjusted income from equity investments decreased $8.7 million to $7.1 million in 2016 compared to $15.8 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 due to transmission line outages and higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing.

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” in the table below, 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

- 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 (recorded in “OM&G” and “Other income (expenses), net” in the table below).

- Emera Utility Services is a utility services contractor primarily operating in Atlantic Canada (recorded in “Non-regulated operating revenue” in the table below).

- 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. This will continue until the Maritime Link Project goes into service, which is expected in 2017.

    - Emera’s 60.5 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 of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL 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 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 $ 543.9 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 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 Consolidated Statements of Income until its sale on May 24, 2016. The common shares are now included in “Investment securities” on the Consolidated Balance Sheets.

- Other investments.

Mark-to-Market Adjustments

Specific to the TECO Energy acquisition, Emera has recorded after-tax mark-to-market gains of $4.9 million for the three months ended June 30, 2016 (2015 – nil) and after-tax mark-to-market losses of $116.2 million for the six months ended June 30, 2016 (2015 – nil) related to the effect of the Debenture Offering related USD-denominated currency and forward contracts put in place to hedge the anticipated proceeds from the final instalment of the Debenture Offering of the acquisition, which closed on July 1, 2016.

“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 below shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

Review of 2016

Corporate and Other

For the millions of Canadian dollars	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Intercompany revenue (1)	**$ 9.6**	$ 9.3	**$ 19.5**	$ 14.6
Non-regulated operating revenue	**7.8**	9.1	**16.2**	17.9
Non-regulated direct costs	**6.7**	10.8	**14.9**	20.5
Operating, maintenance and general	**19.9**	10.2	**33.6**	22.9
Depreciation and amortization	**0.8**	0.3	**1.5**	0.6
Total operating expenses	**27.4**	21.3	**50.0**	44.0
Income (loss) from operations	**(10.0)**	(2.9)	**(14.3)**	(11.5)
Income (loss) from equity investments	**18.5**	13.9	**36.6**	25.8
Other income (expenses), net (2)	**234.0**	0.1	**237.6**	(0.1)
Interest expense	**66.2**	5.9	**99.3**	12.2
Adjusted income (loss) before provision for income taxes	**176.3**	5.2	**160.6**	2.0
Income tax expense (recovery) (3)	**7.6**	(2.5)	**(6.1)**	(10.4)
Preferred stock dividends	**7.0**	7.8	**14.0**	15.5
Adjusted contribution to consolidated net income	**$ 161.7**	$ (0.1)	**$ 152.7**	$ (3.1)
After-tax mark-to-market gain (loss)	**4.9**	-	**(116.2)**	-
Contribution to consolidated net income	**$ 166.6**	$ (0.1)	**$ 36.5**	$ (3.1)
Adjusted contribution to consolidated earnings per common share – basic	**1.08**	-	**1.02**	(0.02)
Contribution to consolidated earnings per common share – basic	**$ 1.11**	$ -	**$ 0.24**	$ (0.02)
Adjusted EBITDA	**$ 243.3**	$ 11.4	**$ 261.4**	$ 14.8

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

(2) Other income (expenses) net, excludes a pre-tax mark-to-market gain of $6.4 million in Q2 2016 (2015 - nil) and a loss of $133.1 million YTD in 2016 (2015 - nil).

(3) Income tax expense (recovery), excludes a $1.5 million expense (2015 - nil) in Q2 2016 and a recovery of $16.9 million YTD in 2016 (2015 - nil) relating to mark-to-market gains (loss).

Corporate and Other contribution to consolidated net income increased $166.7 million to $166.6 million in Q2 2016 compared to $(0.1) million in Q2 2015. Year-to-date, Corporate and Other contribution to consolidated net income increased $39.6 million to $36.5 million in 2016 compared to $(3.1) 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 June 30		Six months ended June 30
Contribution to consolidated net income – 2015	**$**	**(0.1)**	**$**	**(3.1)**
Increased intercompany revenue due to intercompany loan to Emera Energy Generation		0.3		4.9
Increased OM&G primarily due to acquisition costs related to the TECO Energy acquisition and higher deferred compensation		(9.7)		(10.7)
Income from equity investments – see table below for highlights		4.6		10.8
Gain on sale of APUC common shares		172.1		172.1
Gain on conversion of APUC subscription receipts and dividend equivalents into APUC common shares		62.8		62.8
Increased interest expense primarily due to interest on the TECO Energy acquisition related Convertible Debentures		(60.3)		(87.1)
Decreased income tax recovery primarily due to increased income before provision for income taxes, partially offset by non-taxable portion of gains on APUC transactions and changes in the proportion of income earned in higher tax rate foreign jurisdictions		(10.1)		(4.3)
After-tax mark-to-market gain (loss) - see table below for highlights		4.9		(116.2)
Other		2.1		7.3
Contribution to consolidated net income – 2016	**$**	**166.6**	**$**	**36.5**

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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Operating, maintenance, and general	**$ 7.4**	$ -	**$ 7.5**	$ -
Interest expense, net	**60.0**	-	**85.5**	-
Income tax expense (recovery)	**(25.4)**	-	**(33.5)**	-
Acquisition related costs	**$ 42.0**	$ -	**$ 59.5**	$ -

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 gains of $6.4 million in Q2 2016 ($4.9 million after-tax gain) and pre-tax losses of $133.1 million year-to-date ($116.2 million after-tax loss) in 2016 are recorded in “Other income (expenses), net” on the Consolidated Statements of Income. These losses offset a pre-tax mark-to-market gain of $118.9 million ($100.5 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 June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Foreign exchange on USD cash	**$ 2.1**	$ -	**$ (42.6)**	$ -
Mark-to-market adjustment on USD forward contracts	**4.3**	-	**(90.5)**	-
Income tax (expense) recovery	**(1.5)**	-	**16.9**	-
After-tax mark-to-market gain (loss)	**$ 4.9**	$ -	**$ (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 June 30		Six months ended June 30	
		2016	2015	**2016**	2015
APUC	**$**	**8.6**	$ 8.5	**$ 17.6**	$ 15.1
NSPML		**4.3**	3.7	**8.7**	7.3
LIL		**5.6**	1.7	**10.3**	3.4
Income from equity investments	**$**	**18.5**	$ 13.9	**$ 36.6**	$ 25.8

Income from equity investments increased $4.6 million to $18.5 million in Q2 2016 compared to $13.9 million in Q2 2015. Year-to-date, income from equity investments increased $10.8 million to $36.6 million in 2016 compared to $25.8 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 June 30	Six months ended June 30
Income from equity investments – 2015	**$ 13.9**	**$ 25.8**
APUC – Higher equity earnings and the reclassification of APUC subscription receipts	0.1	2.5
NSPML – Increase in investment	0.6	1.4
LIL – Increase in investment	3.9	6.9
Income from equity investments – 2016	**$ 18.5**	**$ 36.6**

NSPML has invested approximately $907.7 million as at June 30, 2016 of equity, debt and working capital, including $102.8 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested $ 245.3 million of equity, which is comprised of $203.9 million in equity contributed and $41.4 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 nine 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 $49.0 million year-to-date in 2016.

Emera has invested $282.8 million in the LIL as at June 30, 2016, which is comprised of $251.3 million in equity contributed and $31.5 million of accumulated equity earnings. Equity earnings are being recorded based on an annual rate 8.8 per cent of the equity invested until July 1, 2016, when the rate decreased to 8.5 per cent. 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 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 six months ended June 30, 2016 and 2015 include:

millions of Canadian dollars	**2016**	2015	$ Change
Cash and cash equivalents, beginning of period	**$ 1,073.4**	$ 221.1	$ 852.3
Provided by (used in):			
Operating cash flow before change in working capital	**325.0**	435.1	(110.1)
Change in working capital	**150.7**	(85.3)	236.0
Operating activities	**475.7**	349.8	125.9
Investing activities	**178.2**	63.7	114.5
Financing activities	**5,809.8**	(481.0)	6,290.8
Effect of exchange rate changes on cash and cash equivalents	**(78.2)**	23.1	(101.3)
Cash and cash equivalents, end of period	**$ 7,458.9**	$ 176.7	$ 7,282.2

Operating Cash Flows

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

Investing Cash Flows

Net cash provided by investing activities increased $114.5 million to $178.2 million for the six months ended June 30, 2016 compared to $63.7 million for the same period in 2015. The increase was primarily due to proceeds from the sale of APUC common shares and increased investments in NSPML and LIL in 2016, partially offset by proceeds from the sale of NWP in 2015.

Capital expenditures for the six months ended June 30, 2016, including AFUDC and net of proceeds from disposal of assets, were $235 million compared to $220 million during the same period in 2015. The increase is a result of additional capital spending in NSPI and primarily due to the investment in a solar facility in Emera Caribbean, offset by less capital spending in New England Gas Generating Facilities. Details of the capital spend are shown below:

- $143 million at NSPI (2015 – $112 million);
- $32 million at Emera Maine (2015 – $37 million);
- $45 million at Emera Caribbean (2015 – $18 million);
- $12 million at Emera Energy (2015 – $48 million);
- $3 million in Corporate and Other (2015 – $5 million)

Financing Cash Flows

Net cash provided by financing activities increased $6,290.8 million to $5,809.8 million for the six months ended June 30, 2016 compared to cash used in financing activities of $481.0 million for the same period in 2015. The increase was primarily due to the proceeds of the long-term debt issuance 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 will be used to finance the TECO Energy acquisition.

Contractual Obligations

As at June 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	$ 264.6	$ 49.8	$ 24.0	$ 1,260.4	$ 433.0	$ 7,940.3	$ 9,972.1
Purchased power (1)	113.0	231.4	205.7	200.4	197.1	2,423.5	3,371.1
Solid fuel supply	81.1	93.3	23.9	13.4	-	-	211.7
DSM	14.9	26.9	34.9	-	-	-	76.7
Pension and post-retirement obligations (2)	7.4	19.2	19.8	20.2	20.9	716.7	804.2
Asset retirement obligations	3.8	4.0	4.3	4.2	1.7	315.7	333.7
Interest payment obligations (3)	228.2	443.8	441.6	427.2	394.3	5,034.4	6,969.5
Convertible debentures represented by instalment receipts (4)	2,185.0	-	-	-	-	-	2,185.0
Interest obligations on the Convertible Debentures (4)	32.4	-	-	-	-	-	32.4
Transportation (5)	119.6	122.4	78.2	42.7	44.4	88.6	495.9
Long-term service agreements (6)	38.3	51.7	36.8	58.0	22.4	226.1	433.3
Capital projects	57.8	7.6	-	-	-	-	65.4
Equity investment commitments (7)	350.0	376.9	-	-	-	-	726.9
Leases and other (8)	6.6	21.8	9.3	8.7	7.3	16.5	70.2
	$ 3,502.7	$ 1,448.8	$ 878.5	$ 2,035.2	$ 1,121.1	$ 16,761.8	$ 25,748.1

(1) Annual requirement to purchase 20 to 100 per cent of electricity production from independent power producers over varying contract lengths up to 25 years.
(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 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 June 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. The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 (the "First Instalment) was paid on closing of the Debenture Offerings on September 28, 2015 and October 2, 2015, and the remaining $667 (the "Final Instalment") is payable on August 2, 2016 (the "Final Instalment Date").
(5) Purchasing commitments for transportation of solid 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.

Other Contractual Obligations

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 of $5.5 billion ($4.2 billion USD) in US debt facilities on closing. Further information on the closing is discussed in the development section.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $1.4 billion committed syndicated revolving bank lines of credit per the table below. NSPI has an active commercial paper program for up to $500 million (increased in Q2 2016 from $400 million) of which the full amount outstanding is backed by NSPI's operating credit facility referred to below. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

As at June 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	$ 26	$ 674
NSPI – Operating credit facility	October 2020 – Revolver	600	321	279
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	20	60
Other – in USD – Operating credit facilities	Various	32	3	29

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

Emera is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common equity, preferred equity, bond or other debt offerings and any non-ordinary course asset sales by Emera and its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Debenture Offering, or from any such non-ordinary course asset sales or transactions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn. Any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements contain customary representations and warranties and affirmative and negative covenants of Emera that will closely resemble those in Emera's existing revolving credit facility.

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. The Acquisition Credit Facilities are not included in the table above.

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, including the most recent capital markets transactions relating to the TECO Energy Acquisition.

Credit Ratings

Emera

As a result of the capital markets transactions outlined in the Developments section related to the TECO Energy acquisition, in June 2016, Moody's Investor Services assigned the following new credit ratings to Emera:

Issuer	Baa3 (Stable Outlook)
Senior Unsecured	Baa3
Subordinate	Ba2

Guarantees and Letters of Credit

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

OUTLOOK

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.

This 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 this renewal underscore the intense focus placed by customers and regulators on electricity price and affordability that is required by our franchise agreements and basic rate regulation. Going forward, the ability of energy companies to achieve their growth objectives, environmental targets and other goals, will continue to be a key success factor.

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.

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.

Business Outlook

The TECO Energy acquisition on July 1, 2016, is expected to be accretive to EPS by approximately five per cent in 2017, growing to more than 10 per cent by the third full year (2019) assuming a USD/CAD exchange rate consistent with that at the time of acquisition announcement.

Effective July 1, 2016, Emera’s earnings will include the earnings of TECO Energy. TECO Energy’s earnings are most directly impacted by Tampa Electric, Peoples Gas System and NMGC utilities’ earned rate of return on equity and the capital structure approved by each of their regulators. In addition, earnings are driven by load growth in Florida and New Mexico, the prudent management of operating costs, the approved recovery of regulatory deferrals, and the timing and amount of capital expenditures. Overall, Tampa Electric and Peoples Gas System anticipate earning within their allowed ROE range in 2016 and expect earnings and rate base growth to be generally consistent with prior years, as a result of continued customer growth and a focus on cost control. In 2016, NMGC is expected to experience customer and rate base growth at levels similar to prior years and will continue to focus on cost control. Earnings associated with TECO Energy will be impacted in 2016 by acquisition related costs including the settlement benefits package approved by the NMPRC, as part of the approved stipulation agreement.

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 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.

NSPI

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, 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 high carbon and 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 three-year rate plan for fuel costs which will result in an average annual increase of 1.1 per cent for 2017 through 2019.

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.

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

In March 2016, the Prime Minister met with provincial premiers to begin the development of a pan-Canadian plan to reduce greenhouse gases and issued, the *Vancouver Declaration*. NSPI is providing input to the process both through the Province and through submission of a discussion paper to the relevant working committee. The outcome is considered uncertain.

Capital expenditures for 2016, including AFUDC are forecasted to be $314.8 million (2015 - $274.0 million).

Emera Maine

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'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. 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 calculated on a 10.57 per cent base and represents Emera Maine's best estimate of the probable outcome for the two outstanding complaints, and 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 $89.0 million (2015 - $66.0 million actual), including approximately $42.7 million for transmission projects.

Emera Caribbean

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 forecasted to grow modestly in 2016. With oil being the predominant fuel source for generation of electricity in the Caribbean, reduced oil prices may result in an economic benefit on the island in decreased cost of electricity to ratepayers. In support of renewable sources of generation, BLPC installed a 10 megawatt solar facility in Barbados, which became operational in Q2 2016.

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.

Overall, Emera Caribbean earnings and rate base are expected to be generally consistent with prior years. GBPC's 2016 earnings will reflect its 8.8 per cent allowable return on rate base.

In 2016, Emera Caribbean plans to invest approximately $120.8 million in capital programs in 2016 (2015 - $44.0 million actual). This increase is due to spending on a new solar facility in Barbados, as described above.

Pipelines

The timing of the income from Pipelines is predominately a result of capital lease accounting treatment of the Emera Brunswick Pipeline, which yields declining earnings over the life of the asset.

Pipelines' 2016 earnings are expected to be lower than 2015 as a result of less favourable foreign exchange exposure and higher OM&G costs.

Emera Energy

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/demand factors, can provide higher levels of margin opportunity. Historically margins in Q1 and Q4 have been the highest with increased volatility which creates opportunities for earnings.

In addition to capitalizing on volatility-driven market opportunities, Emera Energy Services expects to continue to grow organically building market share through superior 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 New England Gas Generation 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 as compared to 2015.

In addition to energy margins and ancillary revenue, the New England Gas Generating 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 larger of the two components, are determined through an auction process held annually, three years in advance, 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 New England Gas Generating facilities, and Emera Energy's 50 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 $40.8 million (2015 – $42.0 million actual) in capital projects related to its generating assets in order to further improve reliability and increase plant capacity.

Corporate and Other

Corporate and Other is dependent on the level of business development activity, acquisition related initiatives, which in 2016 will include further costs related to the July 1, 2016 TECO Energy acquisition, including the financing of the transaction, 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, corporate financing costs and other corporate activities.

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 further acquisition costs, associated financing initiatives and interest costs related to the TECO Energy acquisition. The TECO Energy acquisition costs will include a 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 will substantially occur on the anticipated conversion of the convertible debentures to common shares, which is expected in Q3 2016.

In 2016, Corporate and Other expects to invest approximately $8.0 million (2015 - $10.0 million actual).

ENL

NSP Maritime Link Inc. ("NSPML")

Through its subsidiary, NSP Maritime Link Inc., ENL had invested at June 30, 2016, approximately $907.7 million of equity, debt and working capital, including $102.8 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested $245.3 million in contributed equity, comprised of $203.9 million in equity contributed and $41.4 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 nine per cent.

ENL's future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for design and 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 $49.0 million year-to-date in 2016.

Maritime Link Project forecasted equity contributions for 2016 and 2017 are $154.0 million and $159.0 million respectively, with total equity for the Project estimated to be $467.9 million.

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, currently estimated at approximately $3.4 billion. As at June 30, 2016, ENL had invested $282.8 million, comprised of $251.3 million in equity and $31.4 million of accumulated equity earnings in LIL. Equity earnings are recorded based on an annual rate of 8.8 per cent of the equity invested until July 1, 2016, when the rate decreased to 8.5 per cent. 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 $65.2 million.

LIL forecasted equity contributions for 2016 and 2017 are $196.0 million and $217.9 million respectively, with total equity investment, by Emera, in the Project estimated to be approximately $600 million.

Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's consolidated balance sheets.

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 Consolidated Statements of Income:

For the millions of Canadian dollars			Three months ended June 30		Six months ended June 30	
			2016	2015	**2016**	2015
	Nature of Service	**Presentation**				
Sales:						
APUC subsidiary (1)	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ 0.4**	$ -	**$ 2.4**	$ 1.7
Purchases:						
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**1.0**	1.8	**1.3**	2.0
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**(6.9)**	(5.0)	**(15.0)**	(11.3)

(1) APUC subsidiary related party transactions include 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 $0.3 million for the three months ended June 30, 2016 (2015 – $(0.4) million) and $0.5 million for the six months ended June 30, 2016 (2015 – $(0.6) million).

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

As at millions of Canadian dollars	June 30 2016	December 31 2015
Due from related parties:		
NSPML – current	**$ 1.7**	$ 1.6
Subsidiary of APUC – current	**-**	0.7
M&NP – loan receivable – long-term	**2.5**	2.5
Due to related parties:		
M&NP – current	**1.9**	2.1
Net due from (to) related parties	**$ 2.3**	$ 2.7

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.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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 Company is currently undergoing a detailed analysis of its requirements, with an expected implementation date in late 2017.

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.

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, 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 work. 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.

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**June 30 2016**	December 31 2015
Derivative instrument assets (current and other assets)	**$ 11.1**	$ 19.8
Derivative instrument liabilities (current and long-term liabilities)	**(27.3)**	(46.2)
Net derivative instrument assets (liabilities)	**$ (16.2)**	$ (26.4)

Hedging Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Operating revenues – regulated	**$ (1.9)**	$ (1.6)	**$ (5.1)**	$ (3.7)
Non-regulated fuel for generation and purchased power	**(0.9)**	(0.6)	**3.3**	5.0
Income from equity investments	**(0.3)**	(0.1)	**(0.6)**	(0.3)
Effective net gains (losses)	**$ (3.1)**	$ (2.3)	**$ (2.4)**	$ 1.0

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

The Company recognized in net income the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

For the millions of Canadian dollars	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Non-regulated fuel for generation and purchased power	**$ 0.5**	$ 0.3	**$ (0.5)**	$ (0.3)
Ineffective gains (losses)	**$ 0.5**	$ 0.3	**$ (0.5)**	$ (0.3)

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**June 30 2016**	December 31 2015
Derivative instrument assets (current and other assets)	**$ 165.3**	$ 209.9
Regulatory assets (current and other assets)	**26.5**	64.3
Derivative instrument liabilities (current and long-term liabilities)	**(27.9)**	(64.3)
Regulatory liabilities (current and long-term liabilities)	**(164.9)**	(209.9)
Net asset (liability)	**$ (1.0)**	$ -

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended June 30				Six months ended June 30		
		2016		2015		**2016**		2015
Regulated fuel for generation and purchased power (1)	**$**	**(0.7)**	$	5.6	**$**	**2.6**	$	13.5
Net gains (losses)	**$**	**(0.7)**	$	5.6	**$**	**2.6**	$	13.5

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory 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		**June 30 2016**		December 31 2015
Derivative instruments assets (current and other assets)	**$**	**33.6**	$	95.3
Derivative instruments liabilities (current and long-term liabilities)		**(131.2)**		(331.9)
Net derivative instrument assets (liabilities)	**$**	**(97.6)**	$	(236.6)

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 June 30				Six months ended June 30		
		2016		2015		**2016**		2015
Operating revenue - non-regulated	**$**	**35.1**	$	20.5	**$**	**256.7**	$	114.5
Non-regulated fuel for purchased power		**4.5**		(4.1)		**3.8**		(3.9)
Net gains (losses)	**$**	**39.6**	$	16.4	**$**	**260.5**	$	110.6

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**June 30 2016**		December 31 2015
Derivative instrument assets (current and other assets)	**$**	**3.5**	$	92.1
Derivative instrument liabilities (current and long-term liabilities)		**(15.7)**		(2.9)
Net derivative instrument assets (liabilities)	**$**	**(12.2)**	$	89.2

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended June 30				Six months ended June 30		
		2016		2015		**2016**		2015
Interest expense, net	**$**	**0.2**	$	(1.9)	**$**	**(0.1)**	$	(1.9)
Other income (expense)		**(6.5)**		-		**(101.3)**		-
Total gains (losses)	**$**	**(6.3)**	$	(1.9)	**$**	**(101.4)**	$	(1.9)

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 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 June 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 June 30, 2016, which have materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with 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, 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 in Q1 2016 and Q2 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 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 deferred financing costs, as at December 31, 2015, previously presented as other assets, being reclassified as a deduction from the carrying amount of the related long-term debt and “Convertible debentures represented by instalment receipts” on its Consolidated Balance Sheets.

In accordance with ASU 2015-15 *Interest: Imputation of Interest*, the Company continues to present deferred issuance costs related to its revolving credit facilities and related instruments in “Other long-term assets” on its 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 GAAP 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 (Topic 815): 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 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. The 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.

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 in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases (Topic 842)
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 lease 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 Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. The Company is currently in the process of 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 in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q2 2016**	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014
Operating revenues	**$ 499.4**	$ 877.0	$ 731.6	$ 642.3	$ 526.9	$ 888.5	$ 782.7	$ 539.0
Net income attributable to common shareholders	**207.8**	44.3	192.1	35.0	10.0	160.1	151.2	28.2
Adjusted net income attributable to common shareholders	**237.5**	120.2	87.1	23.3	48.0	171.6	78.5	49.9
Earnings per common share – basic	**1.39**	0.30	1.31	0.24	0.07	1.10	1.05	0.20
Earnings per common share – diluted	**1.38**	0.30	1.30	0.24	0.07	1.09	1.02	0.20
Adjusted earnings per common share – basic	**1.59**	0.81	0.59	0.16	0.33	1.18	0.54	0.35

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. 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 season. 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.