Management's Discussion & Analysis

As at May 9, 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 first quarter of 2016 relative to 2015; and its financial position as at March 31, 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 three months ended March 31, 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 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")
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; completion of the TECO Energy, Inc. ("TECO Energy") acquisition; uncertainty regarding the length of time required to complete the TECO Energy acquisition; 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 could reduce demand for electricity; weather; commodity price risk; construction and development risk; unanticipated maintenance and other expenditures; derivative financial instruments and hedging availability and inability to complete the Debenture Offering and the financing; failure by the Company to repay the acquisition credit facilities; alternate sources of funding that would be used to replace the acquisition credit facilities may not be available when needed; 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:

- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and their 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") and Bayside Power Limited Partnership ("Bayside Power" or "Bayside"); 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 the pending acquisition of 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'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 2019.

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 be connected 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 market. 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 have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, environmental concerns (including demand for new, less carbon-intensive and renewable generation), lower-cost natural gas, growing demand for new electric heating solutions, and the requirement for large-scale transmission projects to deliver new energy sources to customers. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving the 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 for customers. 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.

In 2015, approximately 65 per cent of Emera's adjusted net income was earned by its rate-regulated subsidiaries, which is lower than previous years and the Company's strategic target. Specifically, the lower percentage of adjusted net income was the result of a substantial increase in Emera Energy's earnings primarily due to strong performance by the New England Gas Generating Facilities, and a strengthening US dollar. It was not the result of a change in Emera's risk tolerance, nor is it from additional capital allocations to non-regulated businesses. Rather, it was the result of strong operating and financial performance of existing non-regulated investments and businesses. Following the close of the pending TECO Energy acquisition, the Company is expected to achieve its adjusted net income target.

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 recent issue of convertible debentures represented by instalment receipts in relation to the pending 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") 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 pending TECO Energy acquisition related USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.1 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures") for the pending 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 March 31 **2016**		2015
Net income attributable to common shareholders	**$**	**44.3**	$	160.1
After-tax mark-to-market gain (loss)	**$**	**(75.9)**	$	(11.5)
Adjusted net income attributable to common shareholders	**$**	**120.2**	$	171.6
Earnings per common share – basic	**$**	**0.30**	$	1.10
Adjusted earnings per common share – basic	**$**	**0.81**	$	1.18

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 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 March 31 **2016**		2015
Net income	**$**	**54.8**	$	174.1
Interest expense, net		**75.2**		44.4
Income tax expense (recovery)		**26.8**		61.4
Depreciation and amortization		**87.5**		82.8
EBITDA		**244.3**		362.7
Mark-to-market gain (loss), excluding income tax and interest		**(75.1)**		(21.5)
Adjusted EBITDA	**$**	**319.4**	$	384.2

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 in 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 “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 “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

After-Tax Mark-to-Market Losses

After-tax mark-to-market losses increased $64.4 million to $75.9 million in Q1 2016 compared to $11.5 million in Q1 2015 primarily due to reversal of the 2015 gain on USD-denominated currency and forward contracts related to the financing of the pending TECO Energy acquisition and the amortization of 2015 Emera Energy gas transportation assets. This increase was partially offset by the reversal of 2015 mark-to-market losses and changes in gas and power contract positions at Emera Energy.

Acquisition Related Costs

Emera incurred after-tax costs of $17.5 million ($0.12 per common share) in Q1 2016 (2015 – nil) related to its pending acquisition of TECO Energy, including legal, advisory, and financing costs.

As discussed and included above in “After-Tax Mark-to-Market Losses”, the foreign currency earnings effect related to the Debenture Offering USD cash balance and the forward contracts were recorded as a mark-to-market after-tax loss of $121.1 million in “Other income (expenses), net” in Q1 2016 (2015 – nil).

2015

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

In Q1 2016, Emera affiliates in the northeastern United States and Atlantic Canada experienced less demand for electricity as a result of unseasonably warm weather. Specifically, NSPI, Emera Maine and Emera Energy’s New England Gas Generating Facilities results were affected. Below is a table highlighting significant changes between adjusted net income from 2015 to 2016.

For the millions of Canadian dollars		Three months ended March 31
Adjusted net income – 2015	**$**	**171.6**
Emera Energy (largely due to New England Gas Generation Facilities) (1)		(17.0)
Acquisition and financing costs relating to the pending acquisition of TECO Energy (1)		(17.5)
NSPI		(15.5)
2015 gain on the sale of NWP		(11.5)
Increased equity earnings from NSPML and LIL		3.8
Other (1)		6.3
Adjusted net income – 2016	**$**	**120.2**

(1) These numbers include the impact of the stronger USD.

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2016**		2015
Operating revenues	**$**	**877.0**	$ 888.5
Income from operations		**270.0**	232.1
Net income attributable to common shareholders		**44.3**	160.1
After-tax mark-to-market gain (loss)		**(75.9)**	(11.5)
Adjusted net income attributable to common shareholders		**120.2**	171.6
Earnings per common share – basic	**$**	**0.30**	$ 1.10
Earnings per common share – diluted	**$**	**0.30**	$ 1.09
Adjusted earnings per common share – basic	**$**	**0.81**	$ 1.18
Dividends per common share declared	**$**	**0.4750**	$ 0.3875
Adjusted EBITDA	**$**	**319.4**	$ 384.2

For the millions of Canadian dollars (except per share amounts)		Three months ended March 31 **2016**		2015
Operating Unit Contributions to Adjusted Net Income				
NSPI	**$**	**52.5**	$	68.0
Emera Maine		**9.3**		11.5
Emera Caribbean		**9.8**		8.8
Pipelines		**9.7**		9.9
Emera Energy		**47.9**		76.4
Corporate and Other		**(9.0)**		(3.0)
Adjusted net income attributable to common shareholders	**$**	**120.2**	$	171.6
After-tax mark-to-market gain (loss)		**(75.9)**		(11.5)
Net income attributable to common shareholders	**$**	**44.3**	$	160.1

For the millions of Canadian dollars		Three months ended March 31 **2016**		2015
Operating cash flow before changes in working capital	**$**	**232.4**	$	257.5
Change in working capital		**(51.8)**		(137.9)
Operating cash flow	**$**	**180.6**	$	119.6
Investing cash flow	**$**	**(139.3)**	$	195.9
Financing cash flow	**$**	**(45.8)**	$	(259.3)

As at millions of Canadian dollars		**March 31 2016**		December 31 2015
Working capital	**$**	**580.3**	$	599.2
Total assets	**$**	**11,448.6**	$	11,950.0

Q1 Consolidated Income Statement and Operating Cash Flow Highlights

Operational Results

Income from operations increased $37.9 million to $270.0 million in Q1 2016 compared to $232.1 million in Q1 2015 primarily due to mark-to-market increases of $91.7 million, the impact of a stronger USD and increased marketing and trading margin at Emera Energy. This was partially offset by decreased margin at the New England Gas Generating Facilities and decreased income from operations at NSPI.

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

Total operating revenues decreased 1.3 per cent to $877.0 million in Q1 2016 compared to $888.5 million in Q1 2015 primarily due to:

- mark-to-market changes increased operating revenues by $95.9 million.
- a $60.1 million decrease at the New England Gas Generating Facilities reflecting lower hedged and market commodity prices and decreased sales volumes due to weather;
- a $49.0 million decrease in NSPI revenues as a result of lower sales volumes due to weather;
- a $10.5 million decrease at Bayside primarily due to lower power prices;
- a $10.4 million increase at Emera Maine primarily due to the impact of a stronger USD;
- an $8.1 million increase in marketing and trading margin at Emera Energy primarily due to the impact of a stronger USD and growth in the volume of business.

Total operating expenses decreased 7.5 per cent to $607.0 million in Q1 2016 compared to $656.4 million in Q1 2015. This was primarily the result of decreased fuel costs at NSPI and New England Gas Generating Facilities reflecting lower commodity prices and decreased sales volumes due to weather, partially offset by higher operating, maintenance and general expenses (“OM&G”) at NSPI reflecting increased storm costs, and the impact of a stronger USD.

Other income (expenses), net

Other income decreased $161.1 million to $(139.2) million in Q1 2016 compared to $21.9 million in Q1 2015. This was primarily due to mark-to-market losses relating to the effect of 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 increased $30.8 million to $75.2 million in Q1 2016 compared to $44.4 million in Q1 2015 primarily due to interest on convertible debentures represented by instalment receipts related to the pending acquisition of TECO Energy.

Income tax expense (recovery)

Income tax expense decreased $34.6 million to $26.8 million in Q1 2016 compared to $61.4 million in Q1 2015. This was primarily due to decreased income before provision for income taxes including mark-to-market adjustments, partially offset by the non-deductible portion of TECO Energy related mark-to-market losses on USD-denominated currency and forward contracts related to the pending acquisition.

Operating Activities

Net cash provided by operating activities increased $61.0 million to $180.6 million in Q1 2016 compared to $119.6 million in Q1 2015. Cash from operations before changes in working capital decreased by $25.1 million primarily due to decreased margin at the New England Gas Generating Facilities and the payment of financing costs related to the pending acquisition of TECO Energy.

Changes in working capital increased operating cash flows by $86.1 million primarily due to favourable changes in accounts receivable reflecting lower sales volumes at NSPI and favourable changes in inventory reflecting the purchase of emission credits by the New England Gas Generating Facilities in 2015.

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)	Q1 2016 vs Q1 2015	Q1 2015 vs Q1 2014
Impact on income from continuing operations		
Total operating revenues	$ 48.5	$ 43.3
Total operating expenses	(25.7)	(32.5)
Net income	15.8	9.2
Adjusted net income	7.2	11.0
Impact on earnings per share		
Basic	$ 0.11	$ 0.06
Basic -adjusted	$ 0.05	$ 0.08

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

	Three months ended March 31		
Average equivalent of $1.00 USD	2016	2015	2014
CAD	1.38	1.24	1.10

Consolidated Balance Sheets Highlights

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ (73.9)**	Decreased primarily due to the impact of a stronger CAD
Receivables, net	**32.9**	Increased due to seasonal trends of business at NSPI and Emera Energy
Inventory	**(53.5)**	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)	**(239.3)**	Decreased primarily due to the effect of a stronger CAD and settlements of derivative instruments at Emera Energy and NSPI
Prepaid expenses	**22.1**	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	**(173.1)**	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	**64.4**	Increased primarily due to increased investments in LIL and NSPML
Other assets (current and long-term)	**(70.2)**	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)	**(27.5)**	Decreased primarily due to the effect of a stronger CAD on debt held by foreign subsidiaries
Accounts payable	**(22.7)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries
Derivative instruments (current and long-term)	**(218.2)**	Decreased primarily due to settlements of natural gas and power contracts at Emera Energy
Regulatory liabilities (current and long-term)	**(74.4)**	Decreased primarily due to changes in regulated derivatives, partially offset by an increased FAM regulatory liability at NSPI
Other liabilities (current and long-term)	**(47.8)**	Decreased primarily due to the effect of a stronger CAD on the Bear Swamp investment, payment of restructuring costs at Emera Caribbean and timing of accruals
Common stock	**41.5**	Increased primarily due to issuance of common stock for the dividend reinvestment program
Accumulated other comprehensive income	**(130.7)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries
Retained earnings	**(25.7)**	Decreased due to dividends payments in excess of net income
Non-controlling interest in subsidiaries	**(28.8)**	Decreased due to increased ownership by Emera in ECI

Developments

Emera

Pending Acquisition of TECO Energy

On September 4, 2015, the Company announced a definitive agreement (“the acquisition agreement”) for Emera to acquire TECO Energy (NYSE:TE) (“the Transaction”). TECO Energy shareholders will receive $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.4 billion USD and includes the assumption of approximately $3.9 billion USD of debt.

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 which serves nearly 725,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves nearly 365,000 customers across Florida; and New Mexico Gas Co., a regulated gas distribution utility which serves more than 515,000 customers across New Mexico.

The Transaction is expected to close mid-2016. Closing of the pending acquisition remains subject to approval by the New Mexico Public Regulation Commission ("NMPRC"), and the satisfaction of customary closing conditions.

On April 11, 2016, Emera and TECO Energy filed an unopposed Stipulation Agreement reflecting a settlement reached with intervening parties in the acquisition case pending before the NMPRC for approval of Emera's proposed acquisition of TECO Energy and the indirect acquisition of New Mexico Gas Co.

The Stipulation Agreement sets out a number of Emera's commitments including honouring commitments made by TECO Energy in its 2014 acquisition case, investing in the expansion of the natural gas system to underserved communities and the Mexican border, and providing resources to support certain economic growth projects and programs. The Stipulation Agreement is subject to review and approval by the NMPRC. The hearing for Emera's pending acquisition of TECO Energy occurred on May 2, 2016. A decision is expected mid-2016.

On March 23, 2016, The Committee on Foreign Investment in the United States approval was received.

ECI Amalgamation

On February 24, 2016, the common shareholders of ECI approved an amalgamation transaction, which resulted in an Emera wholly owned subsidiary 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

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.

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	2.7
Issued for cash under Purchase Plans at market rate	0.58	26.2
Discount on shares purchased under Dividend Reinvestment Plan	-	(1.2)
Options exercised under senior management stock option plan	0.50	13.6
Employee Share Purchase Plan	-	0.2
March 31, 2016	**148.35**	**$ 2,199.0**

1) During the three months ended March 31 2016, Emera issued 0.06 million (2015 - 1.25 million) common shares to facilitate the creation and issuance of an additional 0.2 million (2015 - 5 million) depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange.

As at April 25, 2016, the amount of issued and outstanding common shares was 148.4 million.

The weighted average shares of common stock outstanding – basic, which includes both issued, outstanding common stock and outstanding deferred share units, for the three months ended March 31, 2016 was 148.7 million (2015 – 144.9 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 March 31 **2016**		2015
Operating revenues – regulated	**$**	**397.5**	$	446.5
Regulated fuel for generation and purchased power (1)		**141.5**		189.4
Regulated fuel adjustment mechanism and fixed cost deferrals		**17.6**		(7.2)
Operating, maintenance and general		**87.4**		79.6
Provincial grants and taxes		**9.7**		9.6
Depreciation and amortization		**48.4**		51.5
Total operating expenses		**304.6**		322.9
Income from operations		**92.9**		123.6
Other expenses, net		**1.3**		3.8
Interest expense, net		**31.0**		28.8
Income before provision for income taxes		**60.6**		91.0
Income tax expense (recovery)		**8.1**		21.0
Net income of Nova Scotia Power Inc.		**52.5**		70.0
Preferred stock dividends		**-**		2.0
Contribution to consolidated net income	**$**	**52.5**	$	68.0
Contribution to consolidated earnings per common share	**$**	**0.35**	$	0.47
EBITDA	**$**	**140.0**	$	171.3

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

In Q1 2016, NSPI's contribution to consolidated net income decreased $15.5 million to $52.5 million compared to $68.0 million in Q1 2015.

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

For the millions of Canadian dollars		Three months ended March 31
Contribution to consolidated net income – 2015	**$**	**68.0**
Decreased electric margin (see Electric Margin section below for explanation)		(19.5)
Increased operating, maintenance and general ("OM&G") expenses primarily due to higher maintenance and storm costs, partially offset by decreased demand side management ("DSM") program costs		(7.8)
Decreased fixed cost deferrals primarily due to 2015 DSM regulatory deferral, partially offset by a reduction in the amount of non-fuel revenues deferred		(5.6)
Decreased income taxes primarily due to decreased income before provision for income taxes		12.9
Decreased depreciation and amortization primarily due to a lower regulatory amortization as a result of a fixed cost deferral from 2012 being fully amortized in 2015		3.1
Other, net (1)		1.4
Contribution to consolidated net income – 2016	**$**	**52.5**

(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 March 31 **2016**	 2015
Electric revenues	**$ 391.7**	$ 440.0
Other revenues	**5.8**	6.5
Operating revenues – regulated	**$ 397.5**	$ 446.5

Electric Revenues

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:

Q1 Electric Sales Volumes
Gigawatt hours (“GWh”)

	2016	2015	2014
Residential	**1,431**	1,589	1,568
Commercial	**840**	919	883
Industrial	**578**	602	601
Other	**79**	111	90
Total	**2,928**	3,221	3,142

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

Q1 Electric Revenues
millions of Canadian dollars

	2016	2015	2014
Residential	**$ 223.4**	$ 248.2	$ 232.8
Commercial	**109.2**	119.4	109.1
Industrial	**48.1**	57.9	55.8
Other	**11.0**	14.5	13.3
Total	**$ 391.7**	$ 440.0	$ 411.0

Electric revenues decreased $48.3 million to $391.7 million in Q1 2016 compared to $440.0 million in Q1 2015. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Electric revenues – 2015	**$**	**440.0**
Decreased fuel related electricity pricing effective January 1, 2016		(3.8)
Decreased commercial and residential sales volume due to weather		(31.5)
Decreased industrial sales volume		(9.6)
Other		(3.4)
Electric revenues – 2016	**$**	**391.7**

Regulated Fuel for Generation and Purchased Power

Q1 Production Volumes
GWh

	2016	2015	2014
Coal and petroleum coke ("petcoke")	**1,688**	2,248	2,273
Natural gas	**285**	164	179
Oil	**141**	249	135
Purchased power – other	**95**	87	47
Total non-renewables	**2,209**	2,748	2,634
Wind and hydro – renewables	**406**	384	416
Purchased power – renewables, including IPP and COMFIT	**469**	317	254
Biomass – renewables	**70**	52	53
Total renewables	**945**	753	723
Total production volumes	**3,154**	3,501	3,357

Q1 Average Fuel Costs

		2016		2015		2014
Dollars per megawatt hour ("MWh") produced	**$**	**45**	$	54	$	51

Average unit fuel costs decreased in Q1 2016 compared to Q1 2015 primarily due to decreased commodity pricing and decreased 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, which typically has a higher cost per MWh.

Regulated fuel for generation and purchased power decreased $47.9 million to $141.5 million in Q1 2016 compared to $189.4 million in Q1 2015. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Regulated fuel for generation and purchased power – 2015	**$**	**189.4**
Change in generation mix		11.2
Decreased commodity prices		(38.2)
Decreased sales volumes		(18.3)
Other		(2.6)
Regulated fuel for generation and purchased power – 2016	**$**	**141.5**

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 million. The incentive was suspended for 2012 to 2015, as a result of UARB approved settlement agreements and is in effect for 2016.

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 $13.7 million of prior years' unrecovered Fuel Costs in 2016. Recovery of these costs began January 1, 2016.

On December 18, 2015, the Electricity Plan Implementation (2015) Act (the "Electricity Plan Act") was enacted by the Province of Nova Scotia. In accordance with the Electricity Plan Act, NSPI filed with the UARB, on March 7, 2016, a three-year rate plan for Fuel Costs, requesting an average increase of 1.3 per cent for 2017 through 2019. A hearing is scheduled for June 13, 2016. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates during this period will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers subsequent to 2019.

The Electricity Plan Act further directed NSPI to apply any non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved and applied to the FAM to be used in the 2017 to 2019 period. The exception to this direction 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 $4.6 million. Therefore, as at December 31, 2015, NSPI had deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

In Q1 2016, NSPI applied $3.8 million of non-fuel revenues to the FAM for periods 2017 to 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 FAM included in the Statements of Income includes the effect of Fuel Costs in both the current and preceding years, specifically, and as detailed in the table 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	**$**	**(28.3)**
Under (over) recovery of current period Fuel Costs		(10.0)
Rebate to (recovery from) customers of prior years’ Fuel Costs		(3.8)
Interest on FAM balance		(0.7)
Application of non-fuel revenues		(3.8)
FAM regulatory liability – Balance as at March 31	**$**	**(46.6)**

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, and 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, whereby NSPI retains or absorbs 10 per cent of the over or under recovered amount to a maximum of $5 million.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI’s customer classes contribute differently to 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 from DSM have the largest effect on non-fuel electric revenues and electric margin. Changes in industrial load, which are generally due to economic conditions, 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. Electric margin, which represents revenues available to cover these costs, has increased in a corresponding manner.

Operating revenues are summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31 **2016**	2015
Fuel electric revenues – current year	**$ 152.0**	$ 165.7
Fuel electric revenues – recovery of preceding years	**3.8**	18.2
Non-fuel electric revenues	**235.9**	256.1
Other revenues	**5.8**	6.5
Operating revenues	**$ 397.5**	$ 446.5

Electric margin is summarized in the following table:

Fuel electric revenues – current year	**$ 152.0**	$ 165.7
Fuel electric revenues – recovery of preceding years	**3.8**	18.2
Total fuel electric revenues	**155.8**	183.9
Regulated fuel for generation and purchased power	**(141.5)**	(189.4)
Regulated fuel adjustment mechanism	**(13.8)**	5.4
Fuel-related foreign exchange gain (loss) (1)	**0.2**	0.1
Net fuel revenue (expense) (2)	**0.7**	-
Non-fuel electric revenues	**235.9**	256.1
Electric margin	**$ 236.6**	$ 256.1

(1) As reported in "Other expenses, net" on the Consolidated Statements of Income.

(2) Net fuel revenue is a result of the FAM incentive.

NSPI’s electric margin decreased $19.5 million to $236.6 million in Q1 2016 compared to $256.1 million in Q1 2015 due to decreased non-fuel electric revenues primarily due to decreased residential and commercial sales reflecting decreased load, primarily due to weather.

Q1 Average Electric Margin/MWh

	2016	2015	2014
Dollars per MWh sold	**$ 81**	$ 80	$ 80

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 March 31	
	2016	2015
Income from operations	**$ 92.9**	$ 123.6
Less:		
Fuel electric revenue	**155.8**	183.9
Other revenue	**5.8**	6.5
Add back:		
Regulated fuel for generation and purchased power	**141.5**	189.4
Operating, maintenance and general	**87.4**	79.6
Provincial grants and taxes	**9.7**	9.6
Depreciation and amortization	**48.4**	51.5
Regulated fuel adjustment mechanism and fixed cost deferrals	**17.6**	(7.2)
Other fuel related costs	**0.7**	-
Electric margin	**$ 236.6**	**$** 256.1

EMERA MAINE

Overview

Emera Maine is a transmission and distribution electric utility with assets of approximately $1.1 billion, serving 158,000 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 traditional 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 March 31 **2016**		2015
Operating revenues – regulated	**$**	**57.7**	$	55.8
Operating revenues – non-regulated		**0.2**		-
Total operating revenues		**57.9**		55.8
Regulated fuel for generation and purchased power		**7.8**		7.7
Transmission pool expense (1)		**6.3**		6.1
Operating, maintenance and general		**15.9**		13.2
Provincial, state and municipal taxes		**3.6**		3.5
Depreciation and amortization		**10.7**		8.8
Total operating expenses		**44.3**		39.3
Income from operations		**13.6**		16.5
Other income (expenses), net		**0.2**		1.1
Interest expense, net		**3.6**		3.4
Income before provision for income taxes		**10.2**		14.2
Income tax expense (recovery)		**3.4**		4.9
Contribution to consolidated net income – USD	**$**	**6.8**	$	9.3
Contribution to consolidated net income – CAD	**$**	**9.3**	$	11.5
Contribution to consolidated earnings per common share – CAD	**$**	**0.06**	$	0.08
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.37**	$	1.24
EBITDA – USD	**$**	**24.5**	$	26.4
EBITDA – CAD	**$**	**33.5**	$	32.8

(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 in Q1 2016 decreased by $2.5 million to $6.8 million compared to $9.3 million in Q1 2015. Highlights of the USD net income changes are summarized in the following table:

For the millions of US dollars		Three months ended March 31
Contribution to consolidated net income – 2015	**$**	**9.3**
Increased operating revenues – (see Operating Revenues – Regulated Section below)		1.9
Increased OM&G primarily due to decreased capitalized construction overheads as a result of lower capital spending and storm costs		(2.7)
Increased depreciation and amortization primarily due to higher plant in service		(1.9)
Other		0.2
Contribution to consolidated net income – 2016	**$**	**6.8**

Emera Maine's CAD contribution to consolidated net income decreased in Q1 2016 by $2.2 million to $9.3 million from $11.5 million in Q1 2015. The impact of a stronger USD, quarter-over-quarter, increased CAD earnings by $0.9 million for the three months ended March 31, 2016.

Operating Revenues – Regulated

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

For the millions of US dollars	Three months ended March 31 **2016**	2015
Electric revenues	**$ 41.7**	$ 40.0
Transmission pool revenues	**11.6**	12.2
Resale of purchased power	**4.4**	3.6
Operating revenues – regulated	**$ 57.7**	$ 55.8

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather.

Q1 Electric Sales Volumes

GWh	**2016**	2015	2014
Residential	**218**	235	232
Commercial	**198**	207	206
Industrial	**81**	101	105
Other	**4**	3	4
Total	**501**	546	547

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

Q1 Electric Revenues
millions of US dollars

	2016	2015	2014
Residential	**$ 20.7**	$ 21.6	$ 20.7
Commercial	**14.8**	14.3	14.9
Industrial	**3.2**	3.3	4.1
Other (1)	**3.0**	0.8	2.7
Total	**$ 41.7**	$ 40.0	$ 42.4

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

Electric revenues increased $1.7 million to $41.7 million in Q1 2016 compared to $40.0 million in Q1 2015. Highlights of the changes are summarized in the following table:

For the millions of US dollars	Three months ended March 31
Electric revenues – 2015	**$ 40.0**
Increased due to rate changes	3.3
Decreased sales volume primarily due to weather	(3.4)
Increased due to FERC transmission rate refund reserves	1.2
Amortization of transmission revenue adjustments	0.6
Electric revenues – 2016	**$ 41.7**

Q1 Average Electric Revenue / MWh

US dollars	**2016**	2015	2014
Dollars per MWh	**$ 83**	$ 73	$ 78

The change in average electric revenue per MWh in Q1 2016 compared to Q1 2015 reflects increased transmission rates and sales mix.

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 March 31		
		2016		2015
Transmission pool revenues	**$**	**11.6**	$	12.2
Transmission pool expenses		**6.3**		6.1
Net transmission pool revenues	**$**	**5.3**	$	6.1

Emera Maine's net transmission pool revenues decreased $0.8 million to $5.3 million in Q1 2016 compared to $6.1 million in Q1 2015 primarily due to changes in the level of investment in regionally funded transmission assets and the effect 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 which is the provider of electricity on the island of 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. Emera completed the purchase of the remaining 4.5 per cent of common shares from minority shareholders of ECI in Q1 2016.

- 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 March 31 **2016**	 2015
Operating revenues – regulated	**$ 71.0**	$ 83.1
Operating revenues – non-regulated	**-**	1.9
Total operating revenues	**71.0**	85.0
Regulated fuel for generation and purchased power	**26.7**	39.1
Non-regulated direct costs	**-**	1.8
Operating, maintenance and general	**21.6**	22.8
Property taxes (1)	**0.6**	0.4
Depreciation and amortization	**9.4**	8.6
Total operating expenses	**58.3**	72.7
Income from operations	**12.7**	12.3
Income from equity investment	**0.4**	0.5
Other income (expenses), net	**0.3**	1.5
Interest expense, net	**2.8**	2.7
Income before provision for income taxes	**10.6**	11.6
Income tax expense (recovery)	**1.0**	1.0
Net income	**9.6**	10.6
Non-controlling interest in subsidiaries	**1.2**	2.2
Preferred stock dividends (2)	**1.3**	1.3
Contribution to consolidated net income – USD	**$ 7.1**	$ 7.1
Contribution to consolidated net income – CAD	**$ 9.8**	$ 8.8
Contribution to consolidated earnings per common share – CAD	**$ 0.07**	$ 0.06
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.38**	$ 1.24
EBITDA – USD	**$ 22.8**	$ 22.9
EBITDA – CAD	**$ 31.5**	$ 28.3

(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 did not change in Q1 2016 compared to Q1 2015.

Emera Caribbean's CAD contribution to consolidated net income increased by $1.0 million to $9.8 million in Q1 2016 compared to $8.8 million in Q1 2015 as a result of a stronger USD.

Operating Revenues – Regulated

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

For the millions of US dollars	Three months ended March 31 **2016**	 2015
Electric revenues – base rates	**$ 44.0**	$ 43.6
Fuel charge	**26.1**	38.6
Total electric revenues	**70.1**	82.2
Other revenues	**0.9**	0.9
Operating revenues – regulated	**$ 71.0**	$ 83.1

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.

Q1 Electric Sales Volumes
GWh

	2016	2015	2014
Residential	**109**	105	104
Commercial	**179**	179	177
Industrial	**23**	27	24
Other	**6**	6	7
Total	**317**	317	312

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

Q1 Electric Revenues
millions of US dollars

		2016		2015		2014
Residential	**$**	**22.5**	$	25.9	$	31.2
Commercial		**39.3**		46.1		58.5
Industrial		**6.8**		8.6		8.4
Other		**1.5**		1.6		1.7
Total	**$**	**70.1**	$	82.2	$	99.8

Electric revenues decreased $12.1 million to $70.1 million in Q1 2016 compared to $82.2 million in Q1 2015. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended March 31
Electric revenues – 2015	**$**	**82.2**
Decreased fuel charge primarily due to lower fuel prices		(12.5)
Increased due to higher sales volumes at BLPC		0.4
Electric revenues – 2016	**$**	**70.1**

Q1 Average Electric Revenue/MWh

US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**221**	$	259	$	320

The change in average electric revenues per MWh in Q1 2016 compared to Q1 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	Three months ended March 31			
millions of US dollars		**2016**		2015
Operating revenues – regulated	**$**	**71.0**	$	83.1
Less: Other revenues		**(0.9)**		(0.9)
Total electric revenues	**$**	**70.1**	$	82.2
Total electric revenues are broken down as follows:				
Electric revenues – base rate	**$**	**44.0**	$	43.6
Fuel charge		**26.1**		38.6
Total electric revenues		**70.1**		82.2
Regulated fuel for generation and purchased power		**26.7**		39.1
Regulatory amortization (1)		**0.6**		0.7
Electric margin	**$**	**42.8**	$	42.4

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

Q1 Average Electric Margin /MWh

US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**135**	$	134	$	133

Electric margin and average electric margin/MWh is consistent quarter over quarter.

Regulated Fuel for Generation and Purchased Power

Q1 Production Volumes
GWh

	2016	2015	2014
Oil	**337**	335	330
Hydro	**9**	7	8
Total	**346**	342	338

Regulated fuel for generation and purchased power decreased $12.4 million to $26.7 million in Q1 2016 compared to $39.1 million in Q1 2015 primarily due to lower fuel prices.

Q1 Average Fuel Costs/MWh

US dollars		**2016**		2015		2014
Dollars per MWh	**$**	**77**	$	114	$	170

The change in average fuel costs in Q1 2016 compared to Q1 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 March 31
	2016	2015
Income from operations	**$ 12.7**	$ 12.3
Less:		
Operating revenues – non-regulated	**-**	1.9
Other revenue	**0.9**	0.9
Add back:		
Non-regulated direct costs	**-**	1.8
Operating, maintenance and general	**21.6**	22.8
Property taxes	**0.6**	0.4
Depreciation and amortization (1)	**8.8**	7.9
Electric margin	**$ 42.8**	**$ 42.4**

(1) Depreciation and amortization excludes $0.6 million of regulatory amortization in Q1 2016 (2015 – $0.7 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	Three months ended March 31			
millions of Canadian dollars (except per share amounts)		**2016**		2015
Operating revenues – regulated	**$**	**12.9**	$	13.1
Operating maintenance and general		**0.1**		0.2
Accretion (1)		**0.1**		0.1
Income from equity investment		**5.9**		5.9
Other income (expenses), net		**(0.2)**		0.7
Interest expense, net (2)		**5.7**		6.2
Adjusted Income before provision for income taxes		**12.7**		13.2
Income tax expense (recovery)		**3.0**		3.3
Adjusted contribution to consolidated net income	**$**	**9.7**	$	9.9
After-tax derivative mark-to-market gain (loss)		**(0.3)**		-
Contribution to consolidated net income	**$**	**9.4**	$	9.9
Adjusted contribution to consolidated earnings per common share	**$**	**0.07**	$	0.07
Contribution to consolidated earnings per common share	**$**	**0.06**	$	0.07
Adjusted EBITDA	**$**	**18.5**	$	19.5

(1) Accretion related to the 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 loss of $0.3 million in Q1 2016 compared to nil for the same period in 2015.

Pipelines' contribution to consolidated net income in Q1 2016 is consistent with Q1 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 March 31 **2016**	 2015
Marketing and trading margin (1)	**$ 46.9**	$ 38.8
Electricity sales (2)	**180.1**	250.9
Total operating revenues – non-regulated	**227.0**	289.7
Non-regulated fuel for generation and purchased power (3)	**114.1**	159.9
Operating, maintenance and general	**25.3**	20.1
Provincial, state and municipal taxes	**0.9**	1.4
Depreciation and amortization	**10.9**	9.3
Total operating expenses	**151.2**	190.7
Adjusted income (loss) from operations	**75.8**	99.0
Income from equity investments (4)	**3.8**	4.0
Other income (expenses), net	**(2.6)**	22.2
Interest expense, net	**6.2**	1.0
Adjusted income (loss) before provision for income taxes	**70.8**	124.2
Income tax expense (recovery) (5)	**22.9**	47.8
Adjusted contribution to consolidated net income (loss)	**$ 47.9**	$ 76.4
After-tax derivative mark-to-market gain (loss)	**$ 45.5**	$ (11.5)
Contribution to consolidated net income	**$ 93.4**	$ 64.9
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.32**	$ 0.53
Contribution to consolidated earnings per common share – basic	**$ 0.63**	$ 0.45
Adjusted EBITDA	**$ 87.9**	$ 134.5

(1) Marketing and trading margin excludes a pre-tax mark-to-market gain of $72.3 million for the quarter ended March 31, 2016 (2015 - $13.9 million gain).
(2) Electricity sales exclude a pre-tax mark-to-market loss of $8.3 million for the quarter ended March 31, 2016 (2015 - $45.8 million loss).
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $2.8 million for the quarter ended March 31, 2016 (2015 - $7.0 million gain).
(4) Income from equity investments excludes a pre-tax mark-to-market loss of $2.4 million for the quarter ended March 31, 2016 (2015 - $3.4 million gain).
(5) Income tax expense (recovery) excludes an $18.9 million expense relating to mark-to-market gains for the quarter ended March 31, 2016 (2015 - $10.0 million recovery).

Emera Energy's contribution to consolidated net income increased $28.5 million to $93.4 million in Q1 2016 compared to $64.9 million in Q1 2015. Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Contribution to consolidated net income – 2015	**$**	**64.9**
Increased marketing and trading margin – See Marketing and Trading Margin below		8.1
Decreased electricity sales primarily due to lower hedged and market power prices at the New England Gas Generating Facilities, lower market prices at Bayside Power, and decreased sales volumes at the New England Gas Generating Facilities driven by weather, partially offset by a stronger USD		(70.8)
Decreased non-regulated fuel for generation and purchased power mainly due to lower hedged and market commodity prices at the New England Gas Generating Facilities, lower market commodity prices at Bayside Power, and decreased purchase volumes at the New England Gas Generating Facilities driven by weather, partially offset by a stronger USD		45.8
Increased OM&G primarily due to a stronger USD and increased performance-based compensation resulting from increased marketing and trading margin		(5.2)
Decreased other income primarily due to a gain on the sale of NWP in 2015		(24.8)
Increased interest expense, net primarily due to higher interest rates on internal financing		(5.2)
Decreased income tax expense primarily due to decreased income before provision for income taxes, changes in the proportion of income earned in higher tax rate foreign jurisdictions and a stronger CAD		24.9
Increased mark-to-market, net of tax primarily due to the reversal of 2015 mark-to-market losses and changes in gas and power contract positions, partially offset by amortization of 2015 gas transportation assets		57.0
Other		(1.3)
Contribution to consolidated net income – 2016	**$**	**93.4**

A portion of earnings are exposed to foreign exchange fluctuations, thereby impacting adjusted CAD contribution to net earnings. The impact of a stronger USD, quarter-over-quarter, increased CAD earnings by $5.3 million in Q1 2016 compared to Q1 2015.

Emera Energy Services

Adjusted EBITDA

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

For the millions of Canadian dollars	Three months ended March 31			
		2016		2015
Marketing and trading margin	**$**	**46.9**	$	38.8
OM&G		**10.4**		7.5
Other income (expenses), net		**(3.7)**		3.5
Adjusted EBITDA	**$**	**32.8**	$	34.8

Marketing and Trading Margin

Marketing and trading margin increased $8.1 million to $46.9 million in Q1 2016 compared to $38.8 million in Q1 2015. This increase is primarily due to a stronger USD and growth in the volume of business, including investment in transportation capacity, which offset the impact of sustained low pricing and volatility in several of Emera Energy's markets in Q1 2016, largely the result of weather.

Other Income

Other income decreased $7.2 million to $(3.7) million in Q1 2016 compared to $3.5 million in Q1 2015. This decrease is primarily due to foreign exchange losses recorded in 2016 as a result of the stronger CAD since December 31, 2015.

Emera Energy Generation

Adjusted EBITDA

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

For the						Three months ended March 31
	New England		Maritime Canada		Total	
millions of Canadian dollars	**2016**	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 139.3**	$ 201.3	**$ 28.3**	$ 39.0	**$ 167.6**	$ 240.3
Capacity and other	**12.5**	10.6	**-**	-	**12.5**	10.6
Electricity sales	**$ 151.8**	$ 211.9	**$ 28.3**	$ 39.0	**$ 180.1**	$ 250.9
Non-regulated fuel for generation and purchased power	**94.1**	133.4	**18.3**	28.6	**112.4**	162.0
Non-regulated electric margin	**$ 57.7**	$ 78.5	**$ 10.0**	$ 10.4	**$ 67.7**	$ 88.9
Provincial taxes	**0.7**	1.1	**0.2**	0.3	**0.9**	1.4
OM&G	**9.0**	7.3	**5.5**	4.5	**14.5**	11.8
Other income (expenses), net	**-**	1.3	**1.1**	(1.3)	**1.1**	-
Adjusted EBITDA	**$ 48.0**	$ 71.4	**$ 5.4**	$ 4.3	**$ 53.4**	$ 75.7

Adjusted EBITDA decreased $22.3 million to $53.4 million in Q1 2016 from $75.7 million in Q1 2015 primarily due to lower margins realized in the New England Gas Generating Facilities, reflecting less favourable short-term economic hedges and fewer optimization opportunities driven by weather across the northeastern United States. This was partially offset by the stronger USD, which contributed $4.7 million.

Operating Statistics

For the						Three months ended March 31
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**1,299**	1,410	**96.1%**	98.0%	**54.6%**	60.8%
Maritime Canada	**518**	483	**95.8%**	99.2%	**75.9%**	70.0%
Total	**1,817**	1,893	**96.0%**	98.3%	**59.3%**	63.1%

(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 decreased quarter-over-quarter at the New England Gas Generating Facilities primarily due to the impact of weather across the northeastern United States.

The New England Gas Generating Facilities sell into price based competitive markets. The primary reason that the overall capacity factor is lower for New England Gas Generating Facilities as compared to the Maritime 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 March 31	
	2016	2015
Bear Swamp	**$ 3.8**	$ 2.1
NWP	**-**	1.9
Adjusted income from equity investments	**$ 3.8**	$ 4.0

Income from equity investments decreased $0.2 million to $3.8 million in Q1 2016 compared to $4.0 million in Q1 2015, largely due to the sale of NWP in Q1 2015 and higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing, largely offset by favourable pricing at Bear Swamp and the effect of a stronger USD.

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

- 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).

Non-consolidated investments (recorded in “Income (loss) from equity investments” in the table below)

- Emera’s 19.4 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”. The investment in APUC is accounted for on the equity basis. There is a one-quarter lag in reporting as APUC’s information is generally not publicly available at the time of Emera’s public release of its financial results. As at March 31, 2016, Emera owned 50.1 million common shares, 12.9 million outstanding subscription receipts and dividend equivalents, at an average conversion price of $9.19. The outstanding subscription receipts and dividend equivalents will automatically convert to common shares in Q4 2016, if an election is not made. If converted, Emera’s interest would increase to 23.2 per cent. The subscription receipts and dividend equivalents are included in “Investments subject to significant influence” on the Consolidated Balance Sheets.

- 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, between 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 59.0 per cent (December 31, 2015 - 55.1 per cent) investment in the partnership capital of LIL, a $3.1 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 2017.

- Other investments.

Mark-to-Market Adjustments

Specific to the pending TECO Energy acquisition, Emera has recorded after-tax mark-to-market losses of $121.1 million for the three months ended March 31, 2016 (2015 – nil) related to the effect of USD-denominated currency and forward contracts put in place to hedge the anticipated proceeds from the second instalment of the Debenture Offering of the pending acquisition, expected to close mid-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 March 31 **2016**	 2015
Intercompany revenue (1)	**$ 9.9**	$ 5.3
Non-regulated operating revenue	**8.4**	8.8
Non-regulated direct costs	**8.2**	9.7
Operating, maintenance and general	**13.7**	12.7
Depreciation and amortization	**0.7**	0.3
Total operating expenses	**22.6**	22.7
Income (loss) from operations	**(4.3)**	(8.6)
Income (loss) from equity earnings	**18.1**	11.9
Other income (expenses), net (2)	**3.6**	(0.2)
Interest expense	**33.1**	6.3
Adjusted income (loss) before provision for income taxes	**(15.7)**	(3.2)
Income tax expense (recovery) (3)	**(13.7)**	(7.9)
Preferred stock dividends	**7.0**	7.7
Adjusted contribution to consolidated net income	**$ (9.0)**	$ (3.0)
After-tax mark-to-market gain (loss)	**(121.1)**	-
Contribution to consolidated net income	**(130.1)**	(3.0)
Adjusted contribution to consolidated earnings per common share – basic	**(0.06)**	(0.02)
Contribution to consolidated earnings per common share – basic	**$ (0.87)**	$ (0.02)
Adjusted EBITDA	**$ 18.1**	$ 3.4

(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 loss of $139.5 million in Q1 2016 compared to nil for the same period in 2015.
(3) Income tax expense (recovery), excludes an $18.4 million recovery relating to mark-to-market losses in Q1 2016 compared to nil for the same period in 2015.

Corporate and Other's contribution to consolidated net income decreased $127.1 million to $(130.1) million in Q1 2016 compared to $(3.0) million in Q1 2015. Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31
Contribution to consolidated net income – 2015	**$ (3.0)**
Increased intercompany revenue primarily due to the issuance of a loan to Emera Energy Generation	4.6
Income from equity investments - see table below for highlights	6.2
Increased interest expense primarily due to interest on the pending TECO Energy acquisition related convertible debentures represented by instalment receipts	(26.8)
Increased income tax recovery primarily due to decreased income before provision for income taxes	5.8
After-tax mark-to-market gain (loss) - see After-Tax Mark-to-Market Gain (Loss) section below	(121.1)
Other	4.2
Contribution to consolidated net income – 2016	**$ (130.1)**

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 March 31		
		2016		2015
Operating, maintenance, and general	**$**	**0.1**	$	-
Interest expense, net		**25.5**		-
Income tax expense (recovery)		**(8.1)**		-
Acquisition related costs	**$**	**17.5**	$	-

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

The foreign currency earnings impact related to the translation from the convertible debenture USD 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. These pre-tax losses totaled $139.5 million in Q1 2016 and are recorded in "Other income (expenses), net" on the Consolidated Statements of Income ($121.1 million after-tax loss). 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 March 31		
		2016		2015
Foreign exchange on USD cash	**$**	**(44.7)**	$	-
Mark-to-market adjustment on USD forward contracts		**(94.8)**		-
Income tax (expense) recovery		**18.4**		-
After-tax mark-to-market gain (loss)	**$**	**(121.1)**	$	-

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31		
		2016		2015
APUC	**$**	**9.0**	$	6.6
NSPML		**4.4**		3.6
LIL		**4.7**		1.7
Income from equity investments	**$**	**18.1**	$	11.9

Income from equity investments increased $6.2 million to $18.1 million in Q1 2016 compared to $11.9 million in Q1 2015. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Income from equity investments – 2015	**$**	**11.9**
APUC – Higher equity earnings and the reclassification of APUC subscription receipts		2.4
NSPML – AFUDC earnings as a result of increased investment		0.8
LIL – AFUDC earnings as a result of increased investment		3.0
Income from equity investments – 2016	**$**	**18.1**

NSPML has invested $796.7 million as at March 31, 2016 of equity, debt and working capital, including $90.3 million of AFUDC, in the development of the Maritime Link Project. Project to date, Emera has invested a total of $206.4 million in equity, which is comprised of $169.3 million in equity contributed and $37.1 million of accumulated retained earnings, with the remaining costs being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent. Proceeds from the federally guaranteed debt financing completed in April 2014, were used to fund project costs until the Project's target 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 and 30 per cent ratio, with equity contributions of $14.4 million in Q1 2016.

Emera has invested $250.4 million in the LIL as at March 31, 2016, which is comprised of $224.5 million in equity contributed and $25.9 million of accumulated equity earnings. Equity earnings are being recorded based on an annual rate 8.8 per cent of the equity invested. 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 three months ended March 31, 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	**232.4**	257.5	(25.1)
Change in working capital	**(51.8)**	(137.9)	86.1
Operating activities	**180.6**	119.6	61.0
Investing activities	**(139.3)**	195.9	(335.2)
Financing activities	**(45.8)**	(259.3)	213.5
Effect of exchange rate changes on cash and cash equivalents	**(69.4)**	28.0	(97.4)
Cash and cash equivalents, end of period	**$ 999.5**	$ 305.3	$ 694.2

Operating Cash Flows

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

Investing Cash Flows

Net cash used in investing activities increased $335.2 million to $139.3 million for the three months ended March 31, 2016 compared to net cash provided by investing activities of $195.9 million for the same period in 2015. The increase was primarily due to proceeds from the sale of NWP in 2015 and increased investments in NSPML and LIL in 2016.

Capital expenditures for the three months ended March 31, 2016, including AFUDC and net of proceeds from disposal of assets, were $87 million compared to $83 million during the same period in 2015. Details of the capital spend are shown below:

- $48 million at NSPI (2015 – $51 million);
- $9 million at Emera Maine (2015 – $19 million);
- $22 million at Emera Caribbean (2015 – $9 million);
- $6 million at Emera Energy (2015 – $2 million);
- $2 million in Corporate and Other (2015 – $2 million)

Financing Cash Flows

Net cash used in financing activities decreased $213.5 million to $45.8 million for the three months ended March 31, 2016 compared to $259.3 million for the same period in 2015. The decrease was primarily due to the repayment of debt in 2015, partially offset by the 2015 proceeds of the long-term debt issuance by Brunswick Pipeline.

Contractual Obligations

As at March 31, 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	$ 268.8	$ 49.5	$ 23.8	$ 610.1	$ 748.5	$ 2,301.2	$ 4,001.9
Purchased power (1)	166.5	229.8	204.0	198.7	195.2	2,380.5	3,374.7
Solid fuel supply	114.5	75.7	12.0	-	-	-	202.2
DSM	22.1	34.0	34.9	-	-	-	91.0
Pension and post-retirement obligations (2)	11.1	19.2	19.8	20.2	20.9	716.7	807.9
Asset retirement obligations	5.1	4.0	4.3	4.2	1.7	317.2	336.5
Interest payment obligations (3)	140.0	177.4	175.1	167.7	138.8	2,244.7	3,043.7
Convertible debentures represented by instalment receipts (4)	727.6	-	-	-	-	-	727.6
Interest obligations on the first instalment of convertible debentures represented by instalment receipts (4)	54.1	-	-	-	-	-	54.1
Transportation (5)	188.9	118.6	78.2	43.2	41.1	86.3	556.3
Long-term service agreements (6)	48.6	49.6	34.4	47.1	20.4	202.1	402.2
Capital projects	69.2	5.6	-	-	-	-	74.8
Equity investment commitments (7)	356.0	183.0	-	-	-	-	539.0
Leases and other (8)	18.9	9.9	9.0	8.4	7.3	19.0	72.5
	$ 2,191.4	$ 956.3	$ 595.5	$ 1,099.6	$ 1,173.9	$ 8,267.7	$ 14,284.4

(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 March 31, 2016, including any expected required payment under associated swap agreements.
(4) In 2015, to finance a portion of the pending 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, with 1/3 paid on closing of the Debenture Offering, and the remaining payable on a date to be fixed following satisfaction of conditions precedent to the closing of the acquisition of TECO Energy.
(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 September 4, 2015, the Company announced a definitive agreement for Emera to acquire TECO Energy for $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.4 billion USD and includes the assumption of approximately $3.9 billion USD of debt. Further information on the pending acquisition of TECO Energy is discussed in the Developments section.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $1.3 billion committed syndicated revolving bank lines of credit per the table below. NSPI has an active commercial paper program for up to $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 March 31, 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	$ 276	$ 424
NSPI – Operating credit facility	October 2020 – Revolver	500	386	114
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	21	59
Other – in USD – Operating credit facilities	Various	32	2	30

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 March 31, 2016.

For the purpose of bridge financing for the pending 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. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing. The credit facilities table above does not include the Acquisition Credit Facilities.

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.

Emera's future liquidity and capital needs, not including the capital needs to fund the pending TECO Energy acquisition, 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.

The cash purchase price of the pending TECO Energy acquisition and the acquisition related costs will be financed at the closing of the acquisition with one or more of the following sources: (i) net proceeds of the first instalment and second instalment under the Debenture Offering, (ii) net proceeds of any subsequently completed preferred equity or bond or other debt offerings, (iii) amounts drawn under the acquisition credit facilities and the revolving facility, and (iv) existing cash on hand and other sources available to the Company. Common equity and other available sources are expected to comprise $1.7 billion USD to $2.1 billion USD of the long-term financing for the acquisition, preferred equity offerings are expected to amount to $0.8 billion USD to $1.2 billion USD and bond or other debt offerings are expected to amount to $3.4 billion USD to $3.8 billion USD.

Emera and its subsidiaries recent financing activity is discussed further in the Developments section.

Guarantees and Letters of Credit

There were no changes in Emera's standby letters of credit since its year end disclosure at 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 pending TECO Energy acquisition will result in further acquisition costs in 2016. The transaction is expected to be accretive to EPS by approximately 5 per cent in the first full year following its completion (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 announcement.   Approximately 95 per cent of the expected foreign exchange exposure to close the pending acquisition has been effectively hedged.

Emera's operations are affected by the US dollar relative to the Canadian dollar. With the disparity between the two currencies, the effect on Emera's income is noteworthy, as approximately 50 per cent of Emera's adjusted net income was derived from subsidiaries with a US functional currency. TECO Energy operations are conducted in US dollars and following the pending acquisition, 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.

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 be generally 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 a three-year rate plan with the UARB for Fuel Costs in Q1 2016, which requested average annual rate increases of 1.3 per cent for 2017 through 2019. NSPI also announced that 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.

In 2015, NSPI filed an application with the UARB for the introduction of a regulatory framework to enable the purchase by retail customers of renewable low-impact electricity generated in Nova Scotia from retail suppliers licensed by the UARB. In Q1 2016, The UARB issued a decision affirming NSPI's proposed framework subject to small revisions. It is expected the market implementation process will be completed by the end of 2016.

Capital expenditures for 2016, including AFUDC are forecasted to be $282.5 million (2015 - $274.0 million actual).

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 outstanding 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 thirteen municipal light departments, seeking to reduce the base transmission ROE to a maximum of 8.93 per cent and the maximum ROE of 11.24 per cent. 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 $89.5 million (2015 - $66 million actual), including approximately $42.9 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 and approved recovery of operating costs, load, and the timing and amount of capital expenditures. Earnings are also affected by the investment returns of Emera's interest in 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.

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 flat compared to 2015.

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.

Emera Caribbean plans to invest approximately $125.2 million in capital programs in 2016 (2015 - $44.0 million actual). This increase is due to spending on a new solar facility in Barbados.

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.

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 $41.0 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, in part, on business development and acquisition related initiatives, which in 2016 will include further costs related to the pending TECO Energy acquisition, 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, growth in APUC earnings (which Emera accounts one quarter after APUC reports such earnings), corporate financing costs and other corporate activities.

Corporate's contribution to consolidated net income in 2016 is expected to be lower than 2015 primarily due to further acquisition costs and associated financing initiatives related to the pending TECO Energy acquisition. These 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 will be recognized once contingencies surrounding regulatory and other approvals are resolved.

On February 9, 2016, APUC announced its intention to acquire The Empire District Electric Company in a $3.4 billion transaction, which is expected to close in Q1 2017. The closing of this transaction and its related financing will reduce Emera's percentage ownership interest in APUC.

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 March 31, 2016, approximately $796.7 million of equity, debt and working capital, including $90.3 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested $206.4 million in equity, comprised of $169.3 million in equity contributed and $37.1 million of accumulated retained earnings, with the remaining costs being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent.

ENL's future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for 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 $14.4 million in Q1 2016.

Maritime Link Project forecasted equity contributions for 2016 and 2017 are $160 million and $156 million respectively, with total equity for the Project estimated to be $470.9 million.

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, currently estimated at approximately $3.1 billion. As at March 31, 2016, ENL has invested $250.4 million, comprised of $224.5 million in equity contributed and $25.9 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. The return on ROE is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB"). There is currently an application filed by another regulated electrical utility in Newfoundland and Labrador, being heard by the NLPUB, which includes a review of ROE. The NLPUB's decision on ROE, expected in Q2 2016, will be applicable for all regulated electrical utilities in Newfoundland and Labrador and become the ROE applicable to ENL's investment in LIL. Future earnings are dependent on the amount and timing of additional equity investments and the approved ROE. Total equity contributions for Q1 2016 for LIL were $38.4 million.

LIL forecasted equity contributions for 2016 and 2017 are $196.0 million and $27.0 million respectively, with total equity investment, by Emera, in the Project estimated to be $409.1 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 March 31	
			2016	2015
	Nature of Service	**Presentation**		
Sales to:				
APUC subsidiary	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ 2.0**	$ 1.6
Purchases from:				
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**0.3**	$ 0.2
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**$ (8.1)**	(6.3)

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 March 31, 2016 (2015 – $(0.2) 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		March 31 2016		December 31 2015
Due from related parties:				
NSPML – current	**$**	**1.2**	$	1.6
Subsidiary of APUC – current		**0.3**		0.7
M&NP – loan receivable – long-term		**2.5**		2.5
Due to related parties:				
M&NP – current		**2.3**		2.1
Net due from (to) related parties	**$**	**1.7**	$	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.

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		**March 31 2016**		December 31 2015
Derivative instrument assets (current and other assets)	**$**	**11.7**	$	19.8
Derivative instrument liabilities (current and long-term liabilities)		**(28.5)**		(46.2)
Net derivative instrument assets (liabilities)	**$**	**(16.8)**	$	(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 March 31 **2016**	 2015
Operating revenues – regulated	**$ (3.2)**	$ (2.1)
Non-regulated fuel for generation and purchased power	**4.2**	5.6
Income from equity investments	**(0.3)**	(0.2)
Effective net gains (losses)	**$ 0.7**	$ 3.3

The effectiveness 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 March 31 **2016**	 2015
Non-regulated fuel for generation and purchased power	**$ (1.0)**	$ (0.6)
Ineffective gains (losses)	**$ (1.0)**	$ (0.6)

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	**March 31 2016**	December 31 2015
Derivative instrument assets (current and other assets)	**$ 131.3**	$ 209.9
Regulatory assets (current and other assets)	**51.5**	64.3
Derivative instrument liabilities (current and long-term liabilities)	**(49.8)**	(64.3)
Regulatory liabilities (current and long-term liabilities)	**(131.3)**	(209.9)
Net asset (liability)	**$ 1.7**	$ -

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 March 31 **2016**	 2015
Regulated fuel for generation and purchased power (1)	**$ 3.0**	$ (1.1)
Net gains (losses)	**$ 3.0**	$ (1.1)

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in “Regulated fuel for generation and purchased power” when the hedged item is consumed.

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		**March 31 2016**		December 31 2015
Derivative instruments assets (current and other assets)	**$**	**33.7**	$	95.3
Derivative instruments liabilities (current and long-term liabilities)		**(141.8)**		(331.9)
Net derivative instrument assets (liabilities)	**$**	**(108.1)**	$	(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 March 31 **2016**		 2015
Operating revenues – non-regulated	**$**	**221.6**	$	94.0
Non-regulated fuel for generation and purchased power		**(0.7)**		0.2
Net gains (losses)	**$**	**220.9**	$	94.2

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		**March 31 2016**		December 31 2015
Derivative instrument assets (current and other assets)	**$**	**1.1**	$	92.1
Derivative instrument liabilities (current and long-term liabilities)		**(7.0)**		(2.9)
Net derivative instrument assets (liabilities)	**$**	**(5.9)**	$	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 March 31
		2016		2015
Other income (expense)	**$**	**(94.8)**	$	-
Interest expense, net		**(0.3)**		-
Total gains (losses)	**$**	**(95.1)**	$	-

DISCLOSURE AND INTERNAL CONTROLS

The Company, under the supervision and participation of management, including the Chief Executive Officer and Chief Financial Officer, has designed as at March 31, 2016 disclosure controls and procedures (“DC&P”) and internal controls over financial reporting (“ICFR”). These terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”).

There have been no changes in Emera or its consolidated subsidiaries’ ICFR for the three months ended on March 31, 2016, which has materially affected, or is reasonably likely to materially affect the Company’s ICFR.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill impairment assessments, income taxes, including deferred taxes, asset retirement obligations, capitalized overhead and valuation of derivative instruments. Actual results may differ significantly from these estimates.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new US GAAP accounting policies that are applicable to, and were adopted by Emera, effective during 2016, are described as follows:

Income Statement – Extraordinary and Unusual Items, Accounting Standard Update ("ASU") 2015-01

In January 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-01, *Income Statement – Extraordinary and Unusual Items,* which simplifies the income statement presentation requirements by eliminating the concept of extraordinary items. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Consolidation, ASU 2015-02

In February 2015, the FASB issued 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 are subject to re-evaluation under the revised consolidation model. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Interest – Imputation of Interest, ASU 2015-03

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 has adopted this standard effective 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 the 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, ASU 2015-04
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. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU 2015-05
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. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Technical Corrections and Improvements, ASU 2015-10
In June 2015, the FASB issued ASU 2015-10, *Technical Corrections and Improvements*, covering a wide range of topics in the codification to correct unintended application of guidance, or make minor improvements to the Codification. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Inventory – Simplifying the Measurement of Inventory, ASU 2015-11
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. ASU 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, ASU 2016-05
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. ASU 2016-05 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and early adoption is permitted. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Investments – Equity Method and Joint Ventures, ASU 2016-07
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. ASU 2016-07 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016, with early adoption permitted. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Future Accounting Pronouncements

Revenue from Contracts with Customers, ASU 2014-09
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification ("ASC"), Topic 606. ASC 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. In March 2016, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers: Principal versus Agent Considerations*. The amendments are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU 2016-10 *Revenue from Contracts with Customers: Identifying Performance Obligations and Licensing*. 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 is continuing to evaluate the impact of adoption of these standards on its consolidated financial statements.

Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities, ASU 2016-01
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. ASU 2016-01 is 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), ASU 2016-02
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. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. ASU 2016-02 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, 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)	**Q1 2016**	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014
Operating revenues	**$ 877.0**	$ 731.6	$ 642.3	$ 526.9	$ 888.5	$ 782.7	$ 539.0	$ 566.6
Net income attributable to common shareholders	**44.3**	192.1	35.0	10.0	160.1	151.2	28.2	24.5
Adjusted net income attributable to common shareholders	**120.2**	87.1	23.3	48.0	171.6	78.5	49.9	44.2
Earnings per common share – basic	**0.30**	1.31	0.24	0.07	1.10	1.05	0.20	0.17
Earnings per common share – diluted	**0.30**	1.30	0.24	0.07	1.09	1.02	0.20	0.17
Adjusted earnings per common share – basic	**0.81**	0.59	0.16	0.33	1.18	0.54	0.35	0.31

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.