Management's Discussion & Analysis

As at November 13, 2015

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments ("Emera") during the third quarter of 2015 relative to 2014; and its financial position as at September 30, 2015 relative to December 31, 2014. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is also presented. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated unaudited condensed consolidated interim financial statements and supporting notes as at and for the nine months ended September 30, 2015; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2014. 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 ("IRC"), Dominica
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
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" within the meaning of applicable Canadian securities laws. The words "anticipates", "believes", "could", "estimates", "expects", "intends", "may", "plans", "projects", "schedule", "should", "will", "would" 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 in this MD&A includes statements which reflect the current view with respect to the Company's objectives, plans, financial and operating performance, business prospects and opportunities. 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 times 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; economic conditions; availability and price of energy and other commodities; capital resources and liquidity risk; the completion of the TECO Energy, Inc. acquisition; the expectation that the acquisition of TECO Energy, Inc. will be accretive to the earnings per share of Emera beginning in 2017; weather; commodity price risk; competitive pressures; construction risk; derivative financial instruments and hedging availability and cost of financing; interest rate risk; counterparty risk; competitiveness of electricity as an energy source; commodity supply; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; loss of service area; 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 separately regarding Emera's consolidated subsidiaries and investments, specifically:

- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and their parent company, Emera (Caribbean) Incorporated ("ECI"), GBPC, Emera Utility Services (Bahamas) Limited ("EUS Bahamas") 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"); and Northeast Wind Partners II, LLC ("NWP") until its sale on January 29, 2015;
- 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;
    - Emera Utility Services Inc. ("Emera Utility Services");
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL") and its investments:
        - NSPML;
        - LIL;
    - Emera Reinsurance Limited;
    - Emera's investment in Algonquin Power & Utilities Corp. ("APUC");
    - Emera's investment in OpenHydro Group Ltd. ("Open Hydro"); 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, as well as gas transmission and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in eastern Canada, the northeastern United States, and the Caribbean.

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 reach customers.

Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions for customers, 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. Core to Emera's strategy is the ability to leverage these particular linkages and adjacencies to create solutions for customers and investment opportunities for the Company.

Emera's strategy is based on 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 continues to target achieving 75 to 85 per cent of its adjusted net income (a non-GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows that fund dividends and reinvestment. Emera has an annual dividend growth target of eight per cent through 2019.

In 2014, 67 per cent of Emera's adjusted net income was earned by its rate-regulated subsidiaries, which is lower than previous years and strategic target, largely as a result of a substantial increase in Emera Energy's earnings from its trading and marketing operations in 2014, as a result of favourable market conditions, as well as from the impact of the acquisition of its New England Gas Generating Facilities in late 2013.

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 issuance in relation to the TECO Energy acquisition. Cash flow from operations will play an increasing role in financing Emera's future growth, although access to debt and equity capital markets will also be an important part of Emera's strategy.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments arising from commodity purchases or trading activities that do not qualify for hedge accounting or regulatory accounting can have a material impact on 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 comparable measures by excluding the effect of:

- mark-to-market adjustments related to Emera's held-for-trading ("HFT") derivative instruments
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp and NWP, until NWP's sale on January 29, 2015
- the amortization of transportation capacity recognized as a result of certain trading and marketing transactions
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline

HFT derivatives do not qualify for hedge accounting or regulatory accounting. They are recognized on the balance sheet at fair value and all gains or losses are recognized in net income for the period. Emera's HFT derivatives are primarily contracts related to the expected purchase and/or supply of electricity and natural gas, which fluctuate in value due to market price volatility of the relevant commodity.

In addition, Brunswick Pipeline has derivative instruments it has not designated as cash flow hedges. These hedges are recognized on the balance sheet at fair value, and all gains and losses are recognized in net income for the period.

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.

Mark-to-market adjustments are further discussed in the Consolidated Financial Highlights section, Emera Energy – Review of 2015, and Pipelines – Review of 2015.

The following is a reconciliation of reported net income attributable to common shareholders to adjusted net income attributable to common shareholders, and reported earnings per common share – basic to adjusted earnings per common share – basic:

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Net income attributable to common shareholders	**$ 35.0**	$ 28.2	**$ 205.1**	$ 255.5
After-tax derivative mark-to-market gain (loss)	**$ 11.7**	$ (21.7)	**$ (37.8)**	$ 14.8
Adjusted net income attributable to common shares	**$ 23.3**	$ 49.9	**$ 242.9**	$ 240.7
Earnings per common share – basic	**$ 0.24**	$ 0.20	**$ 1.41**	$ 1.79
Adjusted earnings per common share – basic	**$ 0.16**	$ 0.35	**$ 1.67**	$ 1.68

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.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to Adjusted Net Income calculations, this measure represents EBITDA absent the earnings 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 September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Net income	**$ 57.3**	$ 49.3	**$ 253.8**	$ 297.5
Interest expense, net	**49.3**	44.5	**141.7**	135.1
Income tax expense (recovery)	**11.7**	(1.7)	**71.7**	59.9
Depreciation and amortization	**84.9**	78.5	**252.0**	247.0
EBITDA	**203.2**	170.6	**719.2**	739.5
Derivative mark-to-market gain (loss), excluding tax and interest	**20.9**	(31.7)	**(53.2)**	21.0
Adjusted EBITDA	**$ 182.3**	$ 202.3	**$ 772.4**	$ 718.5

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.

Emera Energy has a non-regulated electric margin used to show the amount Emera Energy Generation has earned to contribute to the recovery of its non-fuel costs.

Electric margin, as calculated by Emera, may not be comparable to other companies' electric margin measures, 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

2015

Acquisition Related Costs

Emera incurred acquisition related costs, including legal and advisory fees, financing costs including interest on convertible debentures and foreign currency impacts of $20.1 million after-tax ($0.14 per common share) related to its pending acquisition of TECO Energy, Inc. ("TECO Energy"). These costs are reported in Emera's Consolidated Net Income in Q3 2015. Further information on the pending acquisition is in the Developments section of the MD&A.

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

BLPC recorded severance costs of $7.9 million ($6.4 million USD) relating to corporate restructuring, which was recorded in operating, maintenance and general ("OM&G") on the Consolidated Statements of Income in Q2 2015. The after-tax effect on Emera's Consolidated Net Income in Q2 2015 was $5.4 million ($0.04 per common share), as Emera owns 80.7 per cent of ECI, the parent company of BLPC.

These costs have been expensed, and upon completion of its regulatory filing, BLPC has the option to seek regulatory approval to defer these costs.

Sale of Northeast Wind Partnership II, LLC 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, net" on the Consolidated Statements of Income in Q1 2015.

2014

Gain on Dilution of APUC Equity Investment

In September 2014, APUC closed a 16.86 million common share offering. In addition, an over-allotment option of 2.52 million common shares was exercised. As a result, Emera recorded a gain of $10.8 million (after-tax earnings of $9.1 million or $0.06 per common share) in "Income from equity investments". The gain was a result of APUC's share issuance price being higher than Emera's pre-issuance average book value.

CONSOLIDATED FINANCIAL REVIEW

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
Financial Highlights	**2015**	2014	**2015**	2014
Operating revenues	**$ 654.0**	$ 562.4	**$ 2,091.3**	$ 2,179.3
Income from operations	**90.5**	60.0	**358.7**	431.9
Net income attributable to common shareholders	**35.0**	28.2	**205.1**	255.5
After-tax derivative mark-to-market gain (loss)	**11.7**	(21.7)	**(37.8)**	14.8
Adjusted net income attributable to common shareholders	**$ 23.3**	$ 49.9	**$ 242.9**	$ 240.7
Earnings per common share – basic	**$ 0.24**	$ 0.20	**$ 1.41**	$ 1.79
Earnings per common share – diluted	**$ 0.24**	$ 0.20	**$ 1.40**	$ 1.77
Adjusted earnings per common share – basic	**$ 0.16**	$ 0.35	**$ 1.67**	$ 1.68
Dividends per common share declared	**$ 0.8750**	$ 0.7500	**$ 1.6625**	$ 1.4750
Adjusted EBITDA	**$ 182.3**	$ 202.3	**$ 772.4**	$ 718.5

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
Operating Unit Contributions to Adjusted Net Income	**2015**	2014	**2015**	2014
NSPI	**$ 4.9**	$ 10.9	**$ 89.8**	$ 94.8
Emera Maine	**14.7**	13.3	**39.9**	30.7
Emera Caribbean	**13.6**	8.2	**27.2**	22.6
Pipelines	**10.3**	8.7	**29.5**	24.2
Emera Energy	**14.9**	10.7	**94.7**	76.9
Corporate and Other	**(35.1)**	(1.9)	**(38.2)**	(8.5)
Adjusted net income attributable to common shareholders	**$ 23.3**	$ 49.9	**$ 242.9**	$ 240.7
After-tax derivative mark-to-market gain (loss)	**11.7**	(21.7)	**(37.8)**	14.8
Net income attributable to common shareholders	**$ 35.0**	$ 28.2	**$ 205.1**	$ 255.5

For the millions of Canadian dollars	Nine months ended September 30	
Cash Flow Highlights	**2015**	2014
Operating cash flow before changes in working capital	**$ 603.8**	$ 564.3
Change in working capital	**(20.0)**	21.0
Operating cash flow	**$ 583.8**	$ 585.3
Investing cash flow	**$ (122.2)**	$ (403.4)
Financing cash flow	**$ 75.7**	$ (5.8)

As at millions of Canadian dollars	**September 30 2015**	December 31 2014
Working capital	**$ 241.0**	$ 358.3

Q3 Consolidated Income Statement Highlights

Income from operations

Income from operations increased 50.8 per cent to $90.5 million in Q3 2015 compared to $60.0 million in Q3 2014 primarily due to mark-to-market changes of $52.2 million, increased margin at the New England Gas Generating Facilities and the effect of a stronger USD, partially offset by $30.5 million in expenses related to the pending acquisition of TECO Energy and Emera Energy's decreased trading and marketing margin.

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

Total operating revenues increased 16.3 per cent to $654.0 million in Q3 2015 compared to $562.4 million in Q3 2014, primarily due to:

- $56.3 million increase from changes in mark-to-market impacts
- $16.4 million increase at Emera Maine primarily due to the effect of a strengthening USD
- $16.0 million increase and the New England Gas Generating Facilities primarily due to major outage work at Bridgeport Energy in 2014
- $15.9 million increase at NSPI as a result of recovery of prior years' fuel costs from a 2014 UARB settlement agreement
- $10.1 million decrease at BLPC primarily due to lower fuel revenues reflecting lower commodity fuel prices

Total operating expenses increased 12.2 per cent to $563.5 million in Q3 2015 compared to $502.4 million in Q3 2014, primarily due to acquisition costs related to the pending TECO Energy acquisition, the effect of a strengthening USD, increased regulated fuel for generation and purchased power and fixed cost deferrals at NSPI, and increased fuel costs at the New England Gas Generating Facilities reflecting major outage work at Bridgeport Energy in 2014, partially offset by lower commodity fuel prices at BLPC.

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

Income from operations

Income from operations decreased $73.2 million to $358.7 million year-to-date ("YTD") in 2015 compared to $431.9 million during the first nine months in 2014. Mark-to-market changes decreased income from operations by $87.9 million. Increased margin at the New England Gas Generating Facilities and increased operating income at NSPI were partially offset by Emera Energy's decreased trading and marketing margin.

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

Total operating revenues decreased 4.0 per cent to $2,091.3 million year-to-date in 2015 compared to $2,179.3 million in 2014 primarily due to:

- $90.0 million decrease from changes in mark-to-market impacts
- $54.8 million decrease in Emera Energy Services reflecting a return to more normal market levels following particularly strong market conditions in northern United States and Ontario in Q1 2014
- $37.8 million decrease at BLPC primarily due to lower commodity fuel prices
- $63.3 million increase at NSPI as a result of recovery of prior years' fuel costs from 2014 UARB settlement agreement and higher sales volumes, primarily due to weather
- $34.7 million increase at Emera Maine primarily due to the impact of a strengthening USD.

Total operating expenses decreased 0.8 per cent to $1,732.6 million year-to-date in 2015 compared to $1,747.4 million for the same period in 2014. This decrease was primarily due to lower commodity fuel prices at the New England Gas Generating Facilities, Bayside and BLPC, partially offset by increased regulated fuel for generation and purchased power at NSPI, acquisition costs related to the pending TECO Energy acquisition and the impact of a strengthening USD.

Income from equity investments

Income from equity investments increased $31.0 million to $82.2 million year-to-date in 2015 compared to $51.2 million for the first nine months in 2014. Mark-to-market changes increased income from equity investments by $13.7 million. NWP losses in 2014, favourable pricing at Bear Swamp and increased allowance for funds used during construction ("AFUDC") earnings by NSPML contributed to the increase. This was partially offset by a gain on dilution at APUC recorded in 2014.

Other income (expenses), net

Other income increased $16.9 million to $26.3 million year-to-date in 2015 compared to $9.4 million for the same period in 2014. This was primarily due to the gain on the sale of NWP.

Operating Activities

Net cash provided by operating activities decreased $1.5 million to $583.8 million for the nine months ended September 30, 2015 compared to $585.3 million for the same period in 2014. Cash from operations before changes in working capital increased by $39.5 million primarily due to higher margins at the New England Gas Generating Facilities and increased fuel electric revenues at NSPI, partially offset by lower trading and marketing margin at Emera Energy Services, payment of acquisition costs related to the pending TECO Energy acquisition and the deferral of demand side management ("DSM") program costs at NSPI. Changes in working capital decreased operating cash flows by $41.0 million primarily due to payment of taxes by Emera Energy and NSPI, increased receivables reflecting higher revenues at NSPI, and increased dividends payable, partially offset by favourable changes in fuel inventory at NSPI reflecting increased consumption, and lower posted margin at Emera Energy Services.

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)	Q3 2015 vs Q3 2014	Q3 2014 vs Q3 2013
Impact on income from continuing operations		
Total operating revenues	$ 51.8	$ 8.3
Total operating expenses	(42.5)	(8.6)
Net income	6.9	0.2
Adjusted net income	4.9	1.5
Impact on earnings per share		
Basic	$ 0.05	$ -
Adjusted	$ 0.03	$ 0.01

millions of Canadian dollars (except per share amounts)	YTD 2015 vs YTD 2014	YTD 2014 vs YTD 2013
Impact on income from continuing operations		
Total operating revenues	$ 114.5	$ 67.9
Total operating expenses	(97.1)	(51.4)
Net income	15.2	11.6
Adjusted net income	19.0	9.7
Impact on earnings per share		
Basic	$ 0.10	$ 0.08
Adjusted	$ 0.13	$ 0.07

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

	Nine months ended September 30		
Average equivalent of $1.00 USD	2015	2014	2013
CAD	$ 1.26	$ 1.10	$ 1.02

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between September 30, 2015 and December 31, 2014 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ 573.9**	Increased cash provided by financing activities reflecting proceeds from convertible debentures represented by instalment receipts and proceeds of long-term debt, partially offset by payment of debt and common dividends declared; and increased cash used in investing activities reflecting additions to property, plant, and equipment, partially offset by proceeds from the sale of NWP
Receivables, net	**(58.0)**	Decreased primarily due to seasonal trends of business at Emera Energy and NSPI
Income taxes receivable, net of income taxes payable (current and long-term)	**45.4**	Increased primarily due to the payment of taxes owing for the 2014 tax year by EES and NSPI's required prepayment of taxes and interest for reassessments relating to the timing of tax deductions under dispute with the Canada Revenue Agency
Derivative instruments (current and long-term)	**86.1**	Increased primarily due to favourable changes in USD price positions, partially offset by settlements of derivative instruments at NSPI and Emera Energy
Regulatory assets (current and long-term)	**24.6**	Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries and accelerated tax deductions related to property, plant and equipment at NSPI
Property, plant and equipment, net of accumulated depreciation	**470.1**	Increased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries, increased capital expenditures resulting from major outage work at Bridgeport Energy and capital spares recognized at Tiverton Power for 2016 major outage work and increased capital spending at Emera Maine and NSPI, partially offset by depreciation
Investments subject to significant influence	**(108.6)**	Decreased primarily due to the sale of NWP, partially offset by an increased investment in LIL and increase in net assets recorded from investment in APUC
Available-for-sale investments	**26.0**	Increased primarily due to investment by Emera Reinsurance Limited
Goodwill	**34.1**	Increased due to effect of a stronger USD on the translation of Emera’s foreign subsidiaries
Intangibles	**27.4**	Increased primarily due to investment by Emera Maine in a customer information system
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(241.1)**	Decreased primarily due to repayment of debt, partially offset by the issuance of long-term debt by Brunswick Pipeline and the effect of a stronger USD on debt held by foreign subsidiaries
Convertible debentures represented by instalment receipts	**632.7**	Increased primarily due to issuance of convertible debentures related to pending acquisition of TECO Energy
Deferred income tax liabilities, net of deferred income tax assets (current and long-term)	**94.7**	Increased primarily due to accelerated tax deductions related to property, plant and equipment at NSPI and Emera Maine

Derivative instruments (current and long-term)	**21.5**	Increased primarily due to unfavourable mark-to-market impact relating to interest rate and foreign exchange hedges in Brunswick Pipeline
Regulatory liabilities (current and long-term)	**134.4**	Increased primarily due to changes in derivative instruments as a result of favourable USD price positions, partially offset by settlements of derivative instruments at NSPI
Other liabilities (current and long-term)	**111.2**	Increased primarily due to a dividend payable as a result of the fourth quarter dividend declared at the end of Q3 and a long-term service agreement at the New England Generating Facilities
Common stock	**62.1**	Increased primarily due to issuance of common stock from the dividend reinvestment program
Accumulated other comprehensive loss	**(329.9)**	Decreased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries, and from the amortization of unrecognized pension and post-retirement benefit costs at NSPI
Retained earnings	**(35.0)**	Decreased due to dividends paid in excess of net income

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 (“the Transaction”) (NYSE:TE). 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 consolidation 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 more than 700,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves more than 350,000 customers across Florida; and New Mexico Gas Co., also a regulated gas distribution utility which serves more than 510,000 customers across New Mexico. Upon completion of the Transaction, Emera will have over $26 billion of assets and more than 2.4 million electric and gas customers.

Emera has a fully committed $6.5 billion USD bridge facility in place, and financed a portion of the pending acquisition through the sale of $2.185 billion convertible unsecured subordinated debentures, which are described below. The balance of the permanent financing of the Transaction is expected to be obtained before or after closing, from one or more capital market offerings, including debt and preferred equity, as well as from internally generated sources. On October 16, 2015, Emera permanently reduced the USD bridge facility 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 discussed below.

The closing of the Transaction, which is expected to occur in mid-2016, is subject to TECO Energy common shareholder approval and certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Federal Energy Regulatory Commission, the Committee on Foreign Investment in the United States, compliance with any applicable requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the satisfaction of closing conditions.

Convertible Debentures Represented By Instalment Receipts

To finance a portion of the pending acquisition of TECO Energy, on September 28, 2015, Emera, through a direct wholly owned subsidiary (the “Selling Debentureholder”), completed the sale of $1.9 billion aggregate principal amount of 4.0 per cent convertible unsecured subordinated debentures, represented by instalment receipts (the “Debentures” or the “Debenture Offering”).

The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 was paid on closing of the Debenture Offering and the remaining $667 (the “Final Instalment”) is payable on a date (“Final Instalment Date”) to be fixed following satisfaction of conditions precedent to the closing of the acquisition of TECO Energy.

Prior to the Final Instalment Date, the Debentures are represented by instalment receipts. The instalment receipts began trading on the Toronto Stock Exchange (“TSX”) on September 28, 2015 under the symbol “EMA.IR”. The Debentures will not be listed. The Debentures will mature on September 29, 2025 and bear interest at an annual rate of four per cent per $1,000 principal amount of Debentures until and including the Final Instalment Date, after which the interest rate will be 0 per cent. Based on the first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12 per cent, and the effective annual yield thereafter is 0 per cent.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Under the terms of the instalment receipt agreement, Emera agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Company will at all times hold (on a consolidated basis) short-term USD investment grade securities or have cash on hand of not less than the aggregate amount of the first instalment paid on the closing of the Debenture Offering and the exercise of the over-allotment option, in the event of a mandatory redemption.

Approximately $0.6 million ($0.4 million after-tax) in interest expense associated with the Debentures was recognized in Q3 2015 and a total of approximately $19.8 million ($13.7 million after-tax) is expected to be incurred in 2015.

At the option of the holders and provided that payment of the Final Instalment has been made, each Debenture will be convertible into common shares of Emera at any time after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $41.85 per common share. This is a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Company, except that Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions precedent to the closing of the acquisition of TECO Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) April 24, 2017, if notice of the Final Instalment Date has not been given to holders on or before April 21, 2017. Upon any such redemption, the Company will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the instalment receipt in satisfaction of the Final Instalment. In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by Emera at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date.

At maturity, Emera will have the right to pay the principal amount due in common shares, which will be valued at 95 per cent of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment of the Debenture Offering were $632.7 million, or $592.5 million net of issue costs and will be held and invested in short-term USD investment grade securities. The convertible debentures represented by instalment receipts are classified as a current liability on the Consolidated Balance Sheets as the pending acquisition of TECO Energy is expected to close in fiscal 2016.

The net proceeds of the final instalment payment of the Debenture Offering are expected to be, in aggregate, approximately $1.4 billion and will be used, together with the net proceeds of the first instalment payment, to finance, directly or indirectly, the acquisition of TECO Energy and other acquisition related costs.

On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures, subsequent to quarter end, brought the aggregate proceeds of the Debenture Offering to $2.185 billion, assuming payment of the final instalment.

The interest expense associated with the $285 million over-allotment Debentures is approximately $3.0 million ($2.1 million after-tax) and is expected to be incurred in 2015.

Increase in Common Dividend

On August 10, 2015, Emera's Board of Directors approved an increase in the annual common share dividend rate from $1.60 to $1.90. The first payment will be effective November 16, 2015.

Maritime Link Project

On March 6, 2015, NSPML entered into the third of the Maritime Link Project's three major contracts: construction of approximately 400 kilometres of transmission lines in the provinces of Newfoundland and Labrador and Nova Scotia.

NSPML and the Assembly of Nova Scotia Mi'kmaq Chiefs signed a Socio-Economic Agreement for the Maritime Link Project. Under this agreement, NSPML will support ongoing engagement and commitments made during the Environmental Assessment process, including Mi'kmaq participation in environmental monitoring and employment and business opportunities for Mi'kmaq people.

NSPI

New Brunswick Power and NSPI Pilot Project

On March 27, 2015, NSPI and New Brunswick Power jointly announced a pilot project to optimize their generation fleets through cooperative dispatch. Joint savings are expected, but vary subject to changes in relative commodity prices, the benefit of which will flow through to customers.

Emera Maine

Return on Equity (“ROE”) Complaints

On March 3, 2015, the FERC affirmed its June 19, 2014 order approving an ROE on transmission assets of 10.57 per cent for the period of October 1, 2011 to December 31, 2012. This order is in respect of the ROE complaint filed with the FERC by the Attorney General of Massachusetts and other parties on September 30, 2011. The March 3, 2015 order is subject to appeal, and a decision is not expected until Q1 2016 at the earliest.

Recent Financing Activity

Emera

On July 3, 2015, Emera announced it would not redeem the 6,000,000 Cumulative 5-Year Rate Reset First Preferred Shares, Series A Shares (“the Series A Shares”).

On August 17, 2015, Emera announced that 2,135,364 of its 6,000,000 issues and outstanding Series A Shares were tendered for conversion, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series B (the “Series B Shares”). As a result of the conversion, Emera has 3,864,636 Series A Shares and 2,135,364 Series B Shares issued and outstanding. The holders of Series B Shares will be entitled to receive floating rate cumulative preferred cash dividends, as and when declared by the Board of Directors. The dividends are payable quarterly in the amount per share determined by multiplying the applicable quarterly floating dividend rate, which is the sum of the three-month Government of Canada T-bill Rate on the applicable reset date plus 1.84 per cent, by $25.00.

NSPI

NSPI Series I $70 million 8.40 per cent medium-term notes (“MTN”) matured on October 23, 2015.

On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of $25.00 per share for a total of $135 million.

On April 30, 2015, NSPI completed the issuance of $175 million Series AA MTN. The Series AA notes bear interest at a rate of 3.612 per cent per annum until May 1, 2045. The proceeds of the note offering were used for general corporate purposes, including the repayment of maturing corporate term debt.

Brunswick Pipeline

On February 18, 2015, Brunswick Pipeline completed a senior secured financing consisting of a $250 million non-revolving term credit facility bearing interest at bankers’ acceptances rates plus 1.75 per cent and expiring on February 18, 2019. The proceeds were used to reduce borrowings under Emera's revolver, which was previously used to finance the maturity and repayment of an MTN in October 2014.

Emera Energy

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at a fixed rate of 4.89 per cent, and $25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $178 million ($137 million USD) non-taxable distribution in Q4 2015.

Appointments

Executive

On September 22, 2015, Rob Bennett was appointed President and Chief Executive Officer of Emera U.S. Inc., a wholly owned subsidiary of Emera, to lead the TECO Energy integration. Previously, Mr. Bennett had been the Chief Operating Officer, Eastern Canada, with overall executive responsibility for Emera's Eastern Canadian businesses. To facilitate this change, Mr. Bennett's responsibilities are being re-assigned to others within the organization.

On August 31, 2015, Roman Coba was appointed Chief Information Officer of Emera.

On March 30, 2015, Greg Blunden was appointed Vice President, Corporate Strategy & Planning for Emera, reporting to Emera's President & CEO. Mr. Blunden will coordinate Emera's planning and strategy development efforts to grow and expand the Company's business.

On March 3, 2015, Scott Balfour was appointed Chief Operating Officer, Northeast United States and Caribbean, with overall executive responsibility for Emera Energy, Emera Maine and Emera Caribbean. Mr. Balfour will continue to serve as Chief Financial Officer ("CFO"), until a new CFO is appointed.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares		millions of Canadian dollars
December 31, 2013	132.89	$	1,703.0
Issuance of common stock	8.66		242.8
Issued for cash under Purchase Plans at market rate	1.97		66.6
Discount on shares purchased under Dividend Reinvestment Plan	-		(3.0)
Options exercised under senior management stock option plan	0.26		6.2
Stock-based compensation	-		0.8
December 31, 2014	143.78	$	2,016.4
Issued for cash under Purchase Plans at market rate	1.50		62.9
Discount on shares purchased under Dividend Reinvestment Plan	-		(2.9)
Options exercised under senior management stock option plan	0.05		1.5
Stock-based compensation	-		0.6
September 30, 2015	**145.33**	**$**	**2,078.5**

As at October 30, 2015, the amount of issued and outstanding common shares was 145.4 million.
The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended September 30, 2015 was 146.0 million (2014 – 143.6 million) and for the nine months ended September 30, 2015 was 145.4 million (2014 – 142.9 million).

NSPI

Overview

NSPI is a fully-integrated regulated electric utility with assets of approximately $4.5 billion. It is the primary electricity supplier in Nova Scotia providing electricity generation, transmission and distribution services to approximately 505,000 customers. NSPI's target regulated 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 of actual five-quarter average regulated capitalization.

Review of 2015

NSPI Net Income

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30			Nine months ended September 30
		2015	2014		**2015**	2014
Operating revenues – regulated	**$**	**304.9**	$ 289.0	**$**	**1,078.8**	$ 1,015.5
Regulated fuel for generation and purchased power (1)		**110.4**	103.6		**410.4**	384.3
Regulated fuel adjustment mechanism and fixed cost deferrals		**15.8**	15.6		**31.3**	40.9
Operating, maintenance and general		**76.3**	67.7		**231.9**	204.7
Provincial grants and taxes		**9.6**	9.8		**28.8**	28.7
Depreciation and amortization		**51.6**	49.3		**154.3**	151.0
Total operating expenses		**263.7**	246.0		**856.7**	809.6
Income from operations		**41.2**	43.0		**222.1**	205.9
Other expenses, net (2)		**1.7**	1.3		**5.7**	4.3
Interest expense, net		**31.3**	28.7		**90.8**	86.6
Income before provision for income taxes		**8.2**	13.0		**125.6**	115.0
Income tax expense (recovery)		**1.3**	0.1		**29.8**	14.2
Net income of Nova Scotia Power Inc.		**6.9**	12.9		**95.8**	100.8
Preferred stock dividends (3)		**2.0**	2.0		**6.0**	6.0
Contribution to consolidated net income	**$**	**4.9**	$ 10.9	**$**	**89.8**	$ 94.8
Contribution to consolidated earnings per common share	**$**	**0.03**	$ 0.08	**$**	**0.62**	$ 0.66
EBITDA	**$**	**91.1**	$ 91.0	**$**	**370.7**	$ 352.6

(1) Regulated fuel for generation and purchased power includes affiliate transactions and proceeds from the sale of natural gas.
(2) Other expenses, net is included in "Other income (expenses), net" on the Consolidated Statements of Income.
(3) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Consolidated Statements of Income.

NSPI's contribution to consolidated net income decreased $6.0 million to $4.9 million in Q3 2015 compared to $10.9 million in Q3 2014. Year-to-date, NSPI's contribution to consolidated net income decreased $5.0 million to $89.8 million in 2015 compared to $94.8 million in 2014.

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2014	**$**	**10.9**	**$**	**94.8**
Increased electric margin (see Electric Margin section below for explanation)		1.6		12.5
Increased fixed cost deferrals primarily due to the new demand side management ("DSM") regulatory deferral commencing in 2015 and a year-over-year reduction in the amount of non-fuel revenue deferred compared to 2014		5.0		32.2
Increased OM&G expenses primarily due to DSM program costs as a result of legislation, effective January 1, 2015, requiring NSPI to purchase electricity efficiency and conservation activities; these costs have been deferred for recovery over eight years commencing in 2016		(8.8)		(26.3)
Increased depreciation and amortization primarily due to higher property, plant and equipment		(2.3)		(3.3)
Increased interest expense, net primarily due to lower interest revenues related to FAM and fixed cost deferrals and higher long-term debt levels		(2.6)		(4.2)
Increased income tax expense year-over-year is primarily due to decreased tax deductions related to lower pension contributions and increased income before provision for income taxes		(1.2)		(15.6)
Other (1)		2.3		(0.3)
Contribution to consolidated net income – 2015	**$**	**4.9**	**$**	**89.8**

(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 September 30				Nine months ended September 30		
		2015		2014		**2015**		2014
Electric revenues	**$**	**296.0**	$	281.9	**$**	**1,055.6**	$	994.3
Other revenues		**8.9**		7.1		**23.2**		21.2
Operating revenues – regulated	**$**	**304.9**	$	289.0	**$**	**1,078.8**	$	1,015.5

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 season.

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

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

Q3 Electric Sales Volumes
Gigawatt hours ("GWh")

	2015	2014	2013
Residential	**800**	787	794
Commercial	**733**	723	730
Industrial	**663**	657	673
Other	**70**	70	71
Total	**2,266**	2,237	2,268

YTD Electric Sales Volumes
GWh

	2015	2014	2013
Residential	**3,409**	3,287	3,221
Commercial	**2,377**	2,325	2,337
Industrial	**1,865**	1,883	1,970
Other	**255**	237	233
Total	**7,906**	7,732	7,761

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

Q3 Electric Revenues
millions of Canadian dollars

	2015	2014	2013
Residential	**$ 133.8**	$ 126.1	$ 123.4
Commercial	**95.1**	90.0	88.3
Industrial	**55.7**	54.4	48.4
Other	**11.4**	11.4	11.4
Total	**$ 296.0**	$ 281.9	$ 271.5

YTD Electric Revenues
millions of Canadian dollars

	2015	2014	2013
Residential	**$ 545.3**	$ 503.6	$ 480.5
Commercial	**310.0**	290.0	283.8
Industrial	**162.7**	163.6	162.6
Other	**37.6**	37.1	35.4
Total	**$ 1,055.6**	$ 994.3	$ 962.3

Electric revenues increased $14.1 million to $296.0 million in Q3 2015 compared to $281.9 million in Q3 2014. Year-to-date, electric revenues increased $61.3 million to $1,055.6 million in 2015 from $994.3 million during the same period in 2014. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Electric revenues – 2014	**$ 281.9**	**$ 994.3**
Recovery of prior years' fuel costs per November 25, 2014 UARB settlement agreement	11.5	42.6
Increased residential sales volume, largely due to weather	2.0	17.8
Increased commercial sales volume year-to-date, in part due to weather	0.9	6.2
Change in industrial sales volume	0.1	(4.6)
Other	(0.4)	(0.7)
Electric revenues – 2015	**$ 296.0**	**$ 1,055.6**

Regulated Fuel for Generation and Purchased Power

Q3 Production Volumes
GWh

	2015	2014	2013
Coal and petroleum coke ("petcoke")	**1,389**	1,100	1,459
Natural gas	**336**	670	347
Oil	**2**	4	2
Purchased power – other	**110**	133	138
Total non-renewables	**1,837**	1,907	1,946
Wind and hydro – renewables	**260**	188	217
Biomass – renewables	**36**	95	52
Purchased power – renewables	**258**	168	181
Total renewables	**554**	451	450
Total production volumes	**2,391**	2,358	2,396

YTD Production Volumes
GWh

	2015	2014	2013
Coal and petcoke	**4,830**	4,832	5,256
Natural gas	**948**	1,282	894
Oil	**257**	144	56
Purchased power – other	**307**	227	434
Total non-renewables	**6,342**	6,485	6,640
Wind and hydro – renewables	**1,047**	966	901
Biomass – renewables	**143**	196	63
Purchased power – renewables	**855**	594	631
Total renewables	**2,045**	1,756	1,595
Total production volumes	**8,387**	8,241	8,235

Q3 Average Fuel Costs

	2015	2014	2013
Dollars per MWh produced	**$ 46**	$ 44	$ 44

YTD Average Fuel Costs

	2015	2014	2013
Dollars per MWh produced	**$ 49**	$ 47	$ 50

Average unit fuel costs in Q3 2015 increased compared to Q3 2014 due to generation costs associated with the Community Feed-In Tariff (“COMFIT”) program. Increased year-to-date costs in 2015 compared to the same period in 2014 are also due to increased load, which required additional generation to be sourced from higher cost alternatives, increasing the average fuel cost per megawatt (“MWh”) produced.

NSPI’s fuel costs are affected by commodity prices and generation mix which is largely dependent on the economic dispatch of the generating fleet, bringing the lowest cost options on stream first (after renewable energy from independent power producers), such that the incremental cost of production 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, which typically has a higher cost per MWh.

Regulated fuel for generation and purchased power increased $6.8 million to $110.4 million in Q3 2015 compared to $103.6 million in Q3 2014. Year-to-date, regulated fuel for generation and purchased power increased $26.1 million to $410.4 million in 2015 compared to $384.3 million during the same period in 2014. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Regulated fuel for generation and purchased power – 2014	**$**	**103.6**	**$**	**384.3**
Change in generation mix and plant performance		5.4		42.6
Decreased commodity prices		(1.3)		(31.7)
Changes in production volumes		0.8		12.1
Other		1.9		3.1
Regulated fuel for generation and purchased power – 2015	**$**	**110.4**	**$**	**410.4**

Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals

Regulated Fuel Adjustment Mechanism and FAM Regulatory Deferral

NSPI has a Regulated Fuel Adjustment Mechanism which enables it to seek recovery of Fuel Costs (prudently incurred regulated fuel for generation and purchased power and certain fuel-related 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.

A settlement agreement, approved by the UARB in November 2014, is estimated to result in approximately $56.0 million of the 2014 outstanding FAM balance being collected in 2015.

The settlement agreement also reduced the FAM regulatory asset of $86.1 million by $38.2 million through an offset from the amount owing to customers as a result of the Rate Stabilization deferral account, such that at December 31, 2014 the FAM regulatory asset was $47.9 million.

Through a related settlement agreement with stakeholders, in December 2014, NSPI agreed to apply any non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This is effective as of January 1, 2015 until the next General Rate Application ("GRA") approval or similar process where non-fuel rates are adjusted. This settlement agreement requires NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015. As at September 30, 2015, NSPI had exceeded the minimum contribution commitment through the $38.2 million referred to above and an additional $30.1 million year-to-date in 2015.

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		**2015**
FAM regulatory asset – Balance as at January 1	**$**	**47.9**
Under (over) recovery of current period Fuel Costs		15.1
Recovery from customers of prior years' Fuel Costs		(42.6)
Interest on FAM balance		1.4
Application of non-fuel revenue per December 2, 2014 UARB settlement agreement		(30.1)
FAM regulatory liability – Balance as at September 30	**$**	**(8.3)**

Regulated Fixed Cost Deferrals and Fixed Cost Recovery Deferral Regulatory Assets

NSPI has the following regulatory assets arising from UARB approved fixed cost deferral mechanisms:

2015 DSM Deferral

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs are set for 2015 at $35.0 million and are being deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of $102.0 million for the three-year period of 2016 through 2018. A decision on the timing of cost recovery will be made in the future.

The Program Costs are recorded in "OM&G", with an offsetting credit in "Regulated fuel adjustment mechanism and fixed cost deferrals" on Emera's Consolidated Income Statements, with no effect on net earnings, with the exception of interest on the balance.

Details of the DSM regulatory asset, classified in "Regulatory assets" on the Consolidated Balance Sheets, is summarized in the following table:

millions of Canadian dollars		**2015**
DSM regulatory asset – Balance as at January 1	**$**	**-**
Current period Program Costs		26.3
Interest on DSM balance		0.8
DSM regulatory asset – Balance as at September 30	**$**	**27.1**

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a fixed cost recovery for fiscal 2013 and 2014 as part of a rate stabilization plan. As directed by the UARB on November 25, 2014, as discussed above under the Regulated Fuel Adjustment Mechanism, the rate stabilization deferral liability balance of $38.2 million as at December 31, 2014, was applied against the FAM balance in 2014.

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 electric revenues and fuel costs do not have a material effect on NSPI's electric margin or net income.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to the Company's non-fuel electric revenues, with residential and commercial customers contributing more than industrial customers under current rates. Accordingly, changes in residential and commercial load, largely due to the effects of weather and from general economic conditions, 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 facilities to meet legislated greenhouse gas emission reductions and renewable generation requirements is among the drivers increasing NSPI's fixed costs. Electric margin, which represents the 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 September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Fuel electric revenues – current year	**$ 111.2**	$ 109.9	**$ 394.8**	$ 388.3
Fuel electric revenues – recovery of preceding years	**11.5**	-	**42.6**	-
Non-fuel electric revenues	**173.3**	172.0	**618.2**	606.0
Other revenues	**8.9**	7.1	**23.2**	21.2
Operating revenues	**$ 304.9**	$ 289.0	**$ 1,078.8**	$ 1,015.5

Electric margin is summarized in the following table:

Fuel electric revenues – current year	**$ 111.2**	$ 109.9	**$ 394.8**	$ 388.3
Fuel electric revenues – recovery of preceding years	**11.5**	-	**42.6**	-
Total fuel electric revenues	**122.7**	109.9	**437.4**	388.3
Regulated fuel for generation and purchased power	**(110.4)**	(103.6)	**(410.4)**	(384.3)
Regulated fuel adjustment mechanism	**(12.1)**	(6.9)	**(27.5)**	(4.9)
Fuel-related foreign exchange gain (loss) (1)	**(0.2)**	0.3	**0.5**	0.6
Net fuel revenue (expense)	**-**	(0.3)	**-**	(0.3)
Non-fuel electric revenues	**173.3**	172.0	**618.2**	606.0
Electric margin	**$ 173.3**	$ 171.7	**$ 618.2**	$ 605.7

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

NSPI's electric margin increased $1.6 million to $173.3 million in Q3 2015 compared to $171.7 million in Q3 2014 and year-to-date increased $12.5 million to $618.2 million in 2015 compared to $605.7 million during the same period in 2014 primarily due to increased residential sales reflecting increased load, largely due to weather.

Q3 Average Electric Margin/MWh	**2015**	2014	2013
Dollars per MWh sold	**$ 76**	$ 77	$ 71

YTD Average Electric Margin/MWh	**2015**	2014	2013
Dollars per MWh sold	**$ 78**	$ 78	$ 75

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 is discussed further in the Financial Review Electric Margin section.

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Income from operations	**$ 41.2**	$ 43.0	**$ 222.1**	$ 205.9
Less:				
Fuel electric revenues – current and preceding years	**122.7**	109.9	**437.4**	388.3
FAM audit disallowance	**-**	0.3	**-**	0.3
Other revenues	**8.9**	7.1	**23.2**	21.2
Add back:				
Regulated fuel for generation and purchased power	**110.4**	103.6	**410.4**	384.3
Operating, maintenance and general	**76.3**	67.7	**231.9**	204.7
Provincial grants and taxes	**9.6**	9.8	**28.8**	28.7
Depreciation and amortization	**51.6**	49.3	**154.3**	151.0
Regulated fuel adjustment and fixed cost deferrals	**15.8**	15.6	**31.3**	40.9
Electric margin	$ **173.3**	**$** 171.7	**$ 618.2**	**$** 605.7

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.

- For 2015, Emera Maine's allowed ROE on distribution operations is 9.55 per cent, on a common equity component of 49 per cent.
- For local transmission operations, the allowed ROE for the Bangor Hydro district (the franchise electric service territory associated with the former Bangor Hydro Electric Company in eastern and downeast Maine) is 10.57 per cent, pending two outstanding complaints filed with the FERC to challenge the ISO-New England Open Access Transmission Tariff-allowed base ROE of 11.14 per cent and 10.2 per cent is effective June 1 for wholesale and July 1 for retail customers for the Maine Public Service district (the franchise electric service territory associated with the former Maine Public Service Company in northern Maine). 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 an allowed ROE range of 11.07 per cent to 11.74 per cent, pending the two aforementioned complaints filed with FERC. The common equity component of transmission ROE's are based upon the prior calendar year average balances.
- For stranded cost recoveries, the allowed ROE for the Bangor Hydro district is 5.9 per cent, with a common equity component of 48 per cent and for the Maine Public Service district is 7.2 per cent with a common equity component of 50 per cent.

As a result of a rate filing, the following rate changes have been implemented:

Effective July 1, 2015, transmission rates for the Bangor Hydro district increased by approximately 21 per cent in connection with its annual transmission formula rate filing. The increase is associated primarily with the under-recovery of prior year regional transmission revenues collected in local rates, as well as the recovery of increased transmission plant in service.

Effective July 1, 2015, the transmission rates for the Maine Public Service district decreased by approximately 25 per cent in connection with its annual transmission formula rate filing. This decrease was primarily due to an increase in wholesale transmission revenue that allows for a decrease in local customer transmission rates.

Effective January 1, 2015, the stranded cost rates for the Maine Public Service district decreased by approximately 150 per cent. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The reduced stranded cost revenues are offset by reductions in expense and do not affect earnings.

Emera Maine operates under a traditional cost-of-service regulatory structure. All amounts are reported in USD, unless otherwise stated.

Review of 2015
Emera Maine Net Income

For the millions of USD (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Operating revenues – regulated	**$ 59.7**	$ 56.7	**$ 169.0**	$ 163.1
Operating revenues – non-regulated	**0.1**	0.2	**0.5**	0.5
Total operating revenues	**59.8**	56.9	**169.5**	163.6
Regulated fuel for generation and purchased power	**8.2**	6.4	**21.4**	20.3
Transmission pool expense (1)	**7.4**	6.4	**19.3**	17.9
Operating, maintenance and general	**12.3**	12.0	**34.9**	36.7
Provincial, state and municipal taxes	**3.2**	2.7	**10.0**	8.3
Depreciation and amortization	**8.0**	10.7	**27.0**	33.8
Total operating expenses	**39.1**	38.2	**112.6**	117.0
Income from operations	**20.7**	18.7	**56.9**	46.6
Other income (expenses), net	**0.7**	1.0	**2.7**	3.3
Interest expense, net	**3.5**	3.0	**10.3**	8.7
Income before provision for income taxes	**17.9**	16.7	**49.3**	41.2
Income tax expense (recovery)	**6.7**	4.4	**17.6**	13.1
Contribution to consolidated net income – USD	**$ 11.2**	$ 12.3	**$ 31.7**	$ 28.1
Contribution to consolidated net income – CAD	**$ 14.7**	$ 13.3	**$ 39.9**	$ 30.7
Contribution to consolidated earnings per common share – CAD	**$ 0.10**	$ 0.09	**$ 0.27**	$ 0.21
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.31**	$ 1.08	**$ 1.26**	$ 1.09
EBITDA – USD	**$ 29.4**	$ 30.4	**$ 86.6**	$ 83.7
EBITDA – CAD	**$ 38.6**	$ 33.1	**$ 109.2**	$ 91.6

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

Emera Maine’s USD contribution to consolidated net income decreased by $1.1 million to $11.2 million in Q3 2015 compared to $12.3 million in Q3 2014. Year-to-date, Emera Maine’s USD contribution to consolidated net income increased by $3.6 million to $31.7 million in 2015 compared to $28.1 million during the same period in 2014. Highlights of the USD net income changes are summarized in the following table:

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2014	**$**	**12.3**	**$**	**28.1**
Increased operating revenues – see Operating Revenues – Regulated section below		3.0		5.9
Increased regulated fuel for generation and purchased power expense due to changes in long-term purchased power contracts		(1.8)		(1.1)
Increased transmission pool expense due to regional rate increases		(1.0)		(1.4)
Decreased OM&G year-over-year primarily due to increased capitalized construction overheads as a result of higher capital spending in 2015 and the effect of a plan amendment to certain post-retirement medical benefits, partially offset by increased pension expense		(0.3)		1.8
Increased provincial, state and municipal taxes as a result of higher plant in service		(0.5)		(1.7)
Decreased depreciation and amortization primarily due to lower depreciation rates as a result of a 2014 depreciation study and lower stranded cost regulatory amortization		2.7		6.8
Increased interest expense due to higher long-term debt		(0.5)		(1.6)
Increased income tax expense primarily due to decrease in regulatory amortization and increased income before provision for income taxes		(2.3)		(4.5)
Other		(0.4)		(0.6)
Contribution to consolidated net income – 2015	**$**	**11.2**	**$**	**31.7**

Emera Maine’s CAD contribution to consolidated net income increased by $1.4 million to $14.7 million in Q3 2015 from $13.3 million in Q3 2014 and year-to-date increased by $9.2 million to $39.9 million in 2015 from $30.7 million during the same period in 2014. The impact of a stronger USD increased CAD earnings by $2.6 million for the three months ended September 30, 2015 and $5.4 million for the nine months ended September 30, 2015.

Operating Revenues – Regulated

Emera Maine's operating revenues – regulated includes primarily sales of electricity as summarized in the following table:

Q3 Operating Revenues – Regulated
millions of US dollars

		2015		2014
Electric revenues	**$**	**42.1**	$	39.0
Transmission pool revenues		**15.1**		14.7
Resale of purchased power		**2.5**		3.0
Operating revenues – regulated	**$**	**59.7**	$	56.7

YTD Operating Revenues – Regulated
millions of US dollars

		2015		2014
Electric revenues	**$**	**122.0**	$	115.6
Transmission pool revenues		**38.1**		37.7
Resale of purchased power		**8.9**		9.8
Operating revenues – regulated	**$**	**169.0**	$	163.1

Electric Revenues

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

Q3 Electric Sales Volumes

GWh	2015	2014	2013
Residential	**190**	196	195
Commercial	**160**	170	210
Industrial	**161**	149	116
Other	**6**	5	4
Total	**517**	520	525

YTD Electric Sales Volumes

GWh	2015	2014	2013
Residential	**603**	602	592
Commercial	**589**	595	600
Industrial	**329**	322	317
Other	**11**	11	11
Total	**1,532**	1,530	1,520

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

Q3 Electric Revenues
millions of US dollars

		2015	2014	2013
Residential	$	**18.7**	$ 18.4	$ 17.6
Commercial		**14.2**	12.7	13.9
Industrial		**4.7**	4.8	3.3
Other (1)		**4.5**	3.1	0.8
Total	$	**42.1**	$ 39.0	$ 35.6

YTD Electric Revenues
millions of US dollars

		2015	2014	2013
Residential	$	**57.2**	$ 56.0	$ 52.8
Commercial		**43.1**	42.5	40.5
Industrial		**10.9**	10.4	9.5
Other (1)		**10.8**	6.7	4.8
Total	$	**122.0**	$ 115.6	$ 107.6

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

Electric revenues increased $3.1 million to $42.1 million in Q3 2015 compared to $39.0 million in Q3 2014. Year-to-date, electric revenues increased $6.4 million to $122.0 million in 2015 compared to $115.6 million during the same period in 2014. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Electric revenues – 2014	**$**	**39.0**	**$**	**115.6**
(Decreased) increased sales volumes		(0.3)		0.1
Increased primarily due to rate changes		2.5		3.3
Changes in amounts recognized relating to the FERC transmission rate refund		1.3		2.1
(Decreased) increased due to transmission revenue adjustments		(0.4)		0.9
Electric revenues – 2015	**$**	**42.1**	**$**	**122.0**

Q3 Average Electric Revenue / MWh

		2015	2014	2013
Dollars per MWh	$	**81**	$ 75	$ 68

YTD Average Electric Revenue / MWh

		2015	2014	2013
Dollars per MWh	$	**80**	$ 76	$ 71

The change in average electric revenue per MWh in Q3 2015 compared to Q3 2014 and year-to-date in 2015 compared to 2014 reflects transmission revenue adjustments, various rate changes and changes in the amounts recorded related to the transmission rate refund associated with the FERC ROE complaints.

Transmission Pool Revenues and Expenses

Transmission pool expenses are recorded in “Regulated fuel for generation and purchased power” in the Consolidated Statements of Income. Transmission pool revenues are recorded in “Operating revenues – regulated” 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 September 30			Nine months ended September 30	
		2015	2014		**2015**	2014
Transmission pool revenues	**$**	**15.1**	$ 14.7	**$**	**38.1**	$ 37.7
Transmission pool expenses		**7.4**	6.4		**19.3**	17.9
Net transmission pool revenues	**$**	**7.7**	$ 8.3	**$**	**18.8**	$ 19.8

Emera Maine’s net transmission pool revenues decreased $0.6 million to $7.7 million in Q3 2015 compared to $8.3 million in Q3 2014 and year-to-date decreased $1.0 million to $18.8 million in 2015 compared to $19.8 million in 2014, primarily due to changes in the level of investment in regionally funded transmission assets and the impacts of weather in the New England region.

EMERA CARIBBEAN

Overview

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

Consolidated Investments

- 80.7 per cent investment in Emera (Caribbean) Incorporated ("ECI") and its wholly owned subsidiary Barbados Light & Power Company Limited ("BLPC"), a vertically integrated cost-of-service 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 2015 is 10.0 per cent. A fuel pass-through mechanism ensures fuel costs are recovered.

- 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 Grand Bahama Power Company Ltd. ("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 Grand Bahama Port Authority, Grand Bahama. GBPC's approved regulated return on rate base for 2015 is 10.0 per cent. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner.

- 41.8 per cent indirect controlling interest, through ECI's 51.9 per cent controlling interest, in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica. Domlec serves 35,000 customers and is regulated by the Independent Regulatory Commission ("IRC"), Dominica. Domlec's approved regulated return on rate base for 2015 is 15 per cent. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.

- EUS Bahamas, providing utility construction and plant operation services in The Bahamas.

Equity Investment

- 15.4 per cent indirect interest, through ECI's 19.1 per cent interest, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the Caribbean island of St. Lucia that is regulated by the Government of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2015

Emera Caribbean Net Income

For the millions of USD (except per share amounts)		Three months ended September 30				Nine months ended September 30	
		2015		2014		**2015**	2014
Operating revenues – regulated	**$**	**91.9**	$	114.9	**$**	**261.7**	$ 326.7
Operating revenues – non-regulated		**2.1**		1.9		**6.0**	5.8
Total operating revenues		**94.0**		116.8		**267.7**	332.5
Regulated fuel for generation and purchased power		**42.1**		65.5		**121.1**	187.6
Non-regulated direct costs		**2.1**		1.8		**5.7**	5.3
Operating, maintenance and general		**23.6**		28.4		**77.8**	78.7
Property taxes (1)		**0.7**		0.4		**1.6**	1.2
Depreciation and amortization		**8.8**		8.3		**25.9**	25.6
Total operating expenses		**77.3**		104.4		**232.1**	298.4
Income from operations		**16.7**		12.4		**35.6**	34.1
Income from equity investment		**0.5**		0.5		**1.7**	1.7
Other income (expenses), net		**1.3**		2.0		**2.9**	4.4
Interest expense, net		**2.8**		2.9		**8.1**	8.8
Income before provision for income taxes		**15.7**		12.0		**32.1**	31.4
Income tax expense (recovery)		**1.1**		0.7		**0.9**	1.8
Net income		**14.6**		11.3		**31.2**	29.6
Non-controlling interest in subsidiaries		**3.0**		2.5		**7.3**	6.4
Preferred stock dividends (2)		**1.2**		1.2		**2.5**	2.5
Contribution to consolidated net income – USD	**$**	**10.4**	$	7.6	**$**	**21.4**	$ 20.7
Contribution to consolidated net income – CAD	**$**	**13.6**	$	8.2	**$**	**27.2**	$ 22.6
Contribution to consolidated earnings per common share – CAD	**$**	**0.09**	$	0.06	**$**	**0.19**	$ 0.16
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.31**	$	1.08	**$**	**1.27**	$ 1.09
EBITDA – USD	**$**	**27.3**	$	23.2	**$**	**66.1**	$ 65.8
EBITDA – CAD	**$**	**35.6**	$	25.3	**$**	**83.6**	$ 72.0

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

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

Emera Caribbean's USD contribution to consolidated net income increased by $2.8 million to $10.4 million in Q3 2015 compared to $7.6 million in Q3 2014. Year-to-date, Emera Caribbean's USD contribution to consolidated net income increased by $0.7 million to $21.4 million in 2015 compared to $20.7 million during the same period in 2014. Highlights of the net income changes are summarized in the following table:

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2014	**$ 7.6**	$ **20.7**
Increased Electric Margin – see Electric Margin section	0.9	1.9
Decreased OM&G primarily due to a 2014 planned outage at GBPC, savings and timing of maintenance costs and payroll savings at BLPC; year-over-year restructuring costs at BLPC offset the decreased OM&G	4.8	0.9
Decreased other income primarily due to the lower recognition of the Earnings Share Mechanism in GBPC and lower investment gains realized in BLPC Self Insurance Fund	(0.7)	(1.5)
Increased income tax expense quarter-over-quarter primarily due to increased income before provision for income taxes in BLPC; decreased income tax expense year-over-year primarily due to enactment of lower statutory tax rates in Dominica	(0.4)	0.9
Other	(1.8)	(1.5)
Contribution to consolidated net income – 2015	**$ 10.4**	$ **21.4**

Emera Caribbean's CAD contribution to consolidated net income increased by $5.4 million to $13.6 million in Q3 2015 compared to $8.2 million in Q3 2014 and year-over-year increased by $4.6 million to $27.2 million in 2015 compared to $22.6 million during the same period in 2014. The impact of a stronger USD increased CAD earnings by $2.4 million for the three months ended September 30, 2015 and $3.9 million for the nine months ended September 30, 2015.

Operating Revenues – Regulated

Emera Caribbean's operating revenues – regulated include primarily sales of electricity, summarized in the following table:

Q3 Operating Revenues – Regulated
millions of US dollars

	2015	2014
Electric revenues – base rates	**$ 49.7**	$ 48.8
Fuel charge revenues	**41.3**	64.7
Total electric revenues	**91.0**	113.5
Other revenues	**0.9**	1.4
Operating revenues – regulated	**$ 91.9**	$ 114.9

YTD Operating Revenues – Regulated
millions of US dollars

	2015	2014
Electric revenues – base rates	**$ 139.6**	$ 137.5
Fuel charge revenues	**119.1**	185.8
Total electric revenues	**258.7**	323.3
Other revenues	**3.0**	3.4
Operating revenues – regulated	**$ 261.7**	$ 326.7

Electric Revenues

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

Q3 Electric Sales Volumes
GWh

	2015	2014	2013
Residential	**122**	118	116
Commercial	**198**	196	192
Industrial	**25**	26	29
Other	**4**	6	6
Total	**349**	346	343

YTD Electric Sales Volumes
GWh

	2015	2014	2013*
Residential	**338**	329	318
Commercial	**567**	562	553
Industrial	**79**	76	75
Other	**17**	19	19
Total	**1,001**	986	965

* ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

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

Q3 Electric Revenues
millions of US dollars

		2015		2014		2013
Residential	**$**	**31.0**	$	39.4	$	37.2
Commercial		**51.3**		65.8		66.6
Industrial		**7.2**		6.4		8.2
Other		**1.5**		1.9		2.3
Total	**$**	**91.0**	$	113.5	$	114.3

YTD Electric Revenues
millions of US dollars

		2015		2014		2013*
Residential	**$**	**84.0**	$	108.4	$	99.9
Commercial		**147.1**		190.0		188.6
Industrial		**22.9**		19.4		23.9
Other		**4.7**		5.5		5.9
Total	**$**	**258.7**	$	323.3	$	318.3

*ECI acquired a 51.9% controlling interest of Domlec on April 10, 2013.

Electric revenues decreased $22.5 million to $91.0 million in Q3 2015 compared to $113.5 million in Q3 2014. Year-to-date, electric revenues decreased $64.6 million to $258.7 million in 2015 compared to $323.3 million during the same period in 2014. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Electric revenues – 2014	**$**	**113.5**	**$**	**323.3**
Decreased fuel charge revenues primarily due to lower fuel prices		(23.4)		(66.7)
Increased due to higher sales volumes at BLPC and GBPC		0.9		2.1
Electric revenues – 2015	**$**	**91.0**	**$**	**258.7**

Q3 Average Electric Revenue/MWh

		2015		2014		2013
Dollars per MWh	**$**	**261**	$	328	$	333

YTD Average Electric Revenue/MWh

		2015		2014		2013*
Dollars per MWh	**$**	**258**	$	328	$	330

* ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

The change in average electric revenue in Q3 2015 and year-to-date in 2015 compared to Q3 2014 and year-to-date 2014 is a result of the decreased fuel charge primarily due to lower fuel prices.

Electric Margin

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

Electric margin is summarized in the following table:

For the millions of US dollars		Three months ended September 30			Nine months ended September 30	
		2015	2014		**2015**	2014
Operating revenues – regulated	**$**	**91.9**	$ 114.9	**$**	**261.7**	$ 326.7
Less: Other revenues		**(0.9)**	(1.4)		**(3.0)**	(3.4)
Total electric revenues		**91.0**	113.5		**258.7**	323.3
Total electric revenues are broken down as follows:						
Electric revenues – base rate		**49.7**	48.8		**139.6**	137.5
Fuel charge revenues		**41.3**	64.7		**119.1**	185.8
Total electric revenues		**91.0**	113.5		**258.7**	323.3
Regulated fuel for generation and purchased power		**42.1**	65.5		**121.1**	187.6
Regulatory amortization (1)		**0.8**	0.8		**2.2**	2.2
Electric margin	**$**	**48.1**	$ 47.2	**$**	**135.4**	$ 133.5

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

Emera Caribbean's electric margin increased $0.9 million to $48.1 million in Q3 2015 compared to $47.2 million in Q3 2014 and year-to-date increased by $1.9 million to $135.4 million in 2015 compared to $133.5 million during the same period in 2014 due to increased sales volumes at BLPC and GBPC.

Q3 Average Electric Margin / MWh

		2015	2014	2013
Dollars per MWh	**$**	**138**	$ 136	$ 138

YTD Average Electric Margin / MWh

		2015	2014	2013*
Dollars per MWh	**$**	**135**	$ 135	$ 133

*ECI acquired a 51.9% interest of Domlec on April 10, 2013

Regulated Fuel for Generation and Purchased Power

Q3 Production Volumes
GWh

	2015	2014	2013
Oil	**379**	368	354
Hydro	**5**	7	10
Total	**384**	375	364

YTD Production Volumes
GWh

	2015	2014	2013*
Oil	**1,072**	1,048	1,006
Hydro	**19**	23	20
Total	**1,091**	1,071	1,026

*ECI acquired a 51.9% controlling interest of Domlec on April 10, 2013.

Q3 Average Fuel Costs/MWh

		2015	2014	2013
Dollars per MWh	**$**	**110**	$ 175	$ 182

YTD Average Fuel Costs/MWh

		2015	2014	2013*
Dollars per MWh	**$**	**111**	$ 175	183

*ECI acquired a 51.9% controlling interest of Domlec on April 10, 2013.

Average fuel costs decreased in Q3 2015 and year-over-year compared to the same periods in 2014 primarily due to 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 prudently incurred fuel costs are recovered from customers.

The companies' electric margin may not be comparable to other companies' electric margin measures, 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.

For the millions of US dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Income from operations	**$ 16.7**	$ 12.4	**$ 35.6**	$ 34.1
Less:				
Operating revenues – non-regulated	**2.1**	1.9	**6.0**	5.8
Other revenue	**0.9**	1.4	**3.0**	3.4
Add back:				
Non-regulated direct costs	**2.1**	1.8	**5.7**	5.3
Operating, maintenance and general	**23.6**	28.4	**77.8**	78.7
Property taxes	**0.7**	0.4	**1.6**	1.2
Depreciation and amortization (1)	**8.0**	7.5	**23.7**	23.4
Electric margin	**$ 48.1**	$ **47.2**	**$ 135.4**	$ **133.5**

(1) Depreciation and amortization excludes $0.8 million of regulatory amortization in Q3 2015 (2014 – $0.8 million) and $2.2 million YTD in 2015 (2014 – $2.2 million).

PIPELINES

Overview

Pipelines comprises Emera's wholly owned Brunswick Pipeline and the Company's 12.9 per cent interest in 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 agreement is accounted for as a direct financing lease.

- 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 2015

Pipelines' Adjusted Contribution to Consolidated Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Operating revenues – regulated	**$ 13.0**	$ 12.6	**$ 39.1**	$ 36.4
Operating maintenance and general	**0.1**	0.1	**0.3**	0.3
Accretion (1)	**0.1**	0.1	**0.3**	0.2
Income from equity investment	**5.8**	4.9	**16.5**	13.1
Other income (expenses), net	**0.1**	0.5	**0.6**	0.4
Interest expense, net (2)	**5.6**	6.7	**17.3**	19.2
Adjusted income before provision for income taxes	**13.1**	11.1	**38.3**	30.2
Income tax expense (recovery) (3)	**2.8**	2.4	**8.8**	6.0
Adjusted contribution to consolidated net income	**$ 10.3**	$ 8.7	**$ 29.5**	$ 24.2
After-tax derivative mark-to-market gain (loss)	**$ (0.9)**	$ -	**$ (2.3)**	$ -
Contribution to consolidated net income	**$ 9.4**	$ 8.7	**$ 27.2**	$ 24.2
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.07**	$ 0.06	**$ 0.20**	$ 0.17
Contribution to consolidated earnings per common share – basic	**$ 0.06**	$ 0.06	**$ 0.19**	$ 0.17
Adjusted EBITDA	**$ 18.8**	$ 17.9	**$ 55.9**	$ 49.6

(1) Accretion 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 $1.2 million in Q3 2015 and a $3.1 million loss YTD in 2015 compared to nil for the same periods in 2014.

(3) Income tax expense (recovery) excludes a $0.3 million recovery related to mark-to-market losses in Q3 2015 and a $0.8 million recovery relating to mark-to-market losses YTD 2015 compared to nil for the same periods in 2014.

Pipelines' contribution to consolidated net income increased by $0.7 million to $9.4 million in Q3 2015 compared to $8.7 million in Q3 2014. Year-to-date, Pipelines' contribution to consolidated net income increased $3.0 million to $27.2 million in 2015 compared to $24.2 million during the same period in 2014. Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2014	**$ 8.7**	**$ 24.2**
Increased regulated operating revenues due to a stronger USD and increased tolls	0.4	2.7
Increased income from equity investment due to increased interruptible transmission revenue from M&NP	0.9	3.4
Decreased interest expense, net primarily due to a lower interest rate on refinancing in 2015	1.1	1.9
Increased income tax expense primarily due to increased income before provision for income taxes	(0.4)	(2.8)
After-tax derivative mark-to-market gain (loss) on an interest rate swap entered into in Q2 2015	(0.9)	(2.3)
Other	(0.4)	0.1
Contribution to consolidated net income – 2015	**$ 9.4**	**$ 27.2**

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"), consisting of a wholly owned portfolio of electricity generation facilities in New England and Maritime Canada with 1,410 megawatts ("MW") of total capacity;
- Equity investments in the following generation facilities:
    - Emera's 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northern Massachusetts.
    - Emera's 49.0 per cent investment in NWP, a 419 MW portfolio of wind energy projects in the northeastern United States. On January 29, 2015, Emera sold this interest to its 51 per cent partner, First Wind.

Wholly owned investments are consolidated. The investment in Bear Swamp is accounted for on the equity basis. NWP was accounted for on the equity basis, and its results were included until its sale on January 29, 2015. The gain on the sale of this asset is recorded in "Other income, net" on the Consolidated Statements of Income.

Mark-to-Market Adjustments

Emera Energy's "Trading and marketing margin", "Electricity sales", "Non-regulated fuel for generation and purchased power" and "Income from equity investments" are affected by mark-to-market 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 that 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 local gas distribution utilities ("LDC") in the northeast. The AMAs involve Emera Energy supplying gas to the LDCs for a specific term, and the corresponding release of utility owned gas transportation/storage capacity to Emera Energy. Mark-to-market ("MTM") adjustments on these AMAs 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 corresponding transportation asset, which is amortized over the term of each AMA contract. Subsequent changes in gas price differentials, to the extent not offset by the accounting amortization of the transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial in the early months of a contract when delivered volumes and market volatility are usually at peak levels. As a contract is realized, and volumes reduce, volatility is expected to decrease. Ultimately, the transportation asset and the MTM adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM gains and losses may also increase.

Review of 2015

Emera Energy Adjusted Contribution to Consolidated Net Income

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30			Nine months ended September 30
		2015	2014	**2015**	2014
Trading and marketing margin (1)	**$**	**5.2**	$ 9.2	**$ 46.9**	$ 101.7
Electricity sales (2)		**92.8**	78.2	**403.4**	418.3
Total operating revenues – non-regulated		**98.0**	87.4	**450.3**	520.0
Non-regulated fuel for generation and purchased power (3)		**53.7**	50.8	**248.4**	323.2
Operating, maintenance and general		**18.2**	17.6	**58.5**	66.4
Provincial, state and municipal taxes		**-**	-	**0.2**	-
Depreciation and amortization		**10.8**	7.7	**29.8**	28.8
Total operating expenses		**82.7**	76.1	**336.9**	418.4
Adjusted income (loss) from operations		**15.3**	11.3	**113.4**	101.6
Income (loss) from equity investments (4)		**7.4**	5.4	**23.2**	10.7
Other income (expenses), net		**2.0**	1.5	**23.9**	2.1
Interest expense, net		**6.4**	1.5	**13.2**	4.8
Adjusted income (loss) before provision for income taxes		**18.3**	16.7	**147.3**	109.6
Income tax expense (recovery) (5)		**3.4**	6.0	**52.6**	32.7
Adjusted contribution to consolidated net income (loss)	**$**	**14.9**	$ 10.7	**$ 94.7**	$ 76.9
After-tax derivative mark-to-market gain (loss)	**$**	**12.6**	$ (21.7)	**$ (35.5)**	$ 14.8
Contribution to consolidated net income	**$**	**27.5**	$ (11.0)	**$ 59.2**	$ 91.7
Adjusted contribution to consolidated earnings per common share – basic	**$**	**0.10**	$ 0.07	**$ 0.65**	$ 0.54
Contribution to consolidated earnings per common share – basic	**$**	**0.19**	$ (0.08)	**$ 0.41**	$ 0.64
Adjusted EBITDA	**$**	**35.5**	$ 25.9	**$ 190.3**	$ 143.2

(1) Trading and marketing margin excludes a pre-tax mark-to-market gain of $4.6 million in Q3 2015 (2014 - $24.6 million loss) and a loss of $39.3 million YTD in 2015 (2014 - $35.3 million gain)
(2) Electricity sales excludes a pre-tax mark-to-market gain of $20.6 million in Q3 2015 (2014 - $6.5 million loss) and a loss of $17.2 million YTD in 2015 (2014 - $1.8 million loss)
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $4.2 million in Q3 2015 (2014 - $0.1 million loss) and a loss of $0.8 million YTD in 2015 (2014 - $2.9 million loss)
(4) Income from equity investments excludes a pre-tax mark-to-market loss of $0.1 million in Q3 2015 (2014 - $0.5 million loss) and a gain of $4.1 million YTD in 2015 (2014 - $9.6 million loss)
(5) Income tax expense (recovery) excludes a $8.3 million expense relating to mark-to-market gains in Q3 2015 (2014 - $10.0 million recovery) and a $17.7 million recovery relating to mark-to-market losses YTD in 2015 (2014 - $6.2 million expense)

Emera Energy's contribution to consolidated net income increased by $38.5 million to $27.5 million in Q3 2015 compared to $(11.0) million in Q3 2014. Year-to-date, contribution to consolidated net income decreased $32.5 million to $59.2 million in 2015 compared to $91.7 million during the same period in 2014. Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2014	**$**	**(11.0)**	**$**	**91.7**
Decreased trading and marketing margin – See Trading and Marketing Margin section below		(4.0)		(54.8)
Increased electricity sales quarter-over-quarter primarily due to major outage work at Bridgeport in 2014 resulting in reduced generation; decreased year-over year primarily due to lower power prices, partially offset by a stronger USD		14.6		(14.9)
Increased non-regulated fuel for generation and purchased power quarter-over-quarter as a result of major outage work at Bridgeport in 2014 resulting in reduced generation; year-over-year reduction primarily due to lower commodity fuel prices, partially offset by a stronger USD		(2.9)		74.8
Decreased OM&G year-over-year primarily due to decreased performance-based compensation resulting from decreased trading and marketing margin		(0.6)		7.9
Increased income from equity investments – See Equity Investments section below		2.0		12.5
Increased other income year-over-year primarily due to a gain on the sale of NWP		0.5		21.8
Increased interest expense, net primarily due to higher interest rates on internal financing		(4.9)		(8.4)
Decreased income tax expense quarter-over-quarter primarily due to recognition of a valuation allowance related to capital loss carryforwards in Q3 2014 and increased investment tax credits in Q3 2015; increased income tax expense year-over-year primarily due to increased income before provision for income taxes, changes in the proportion of income earned in higher tax rate foreign jurisdictions and a stronger USD		2.6		(19.9)
Increased mark-to-market, net of tax quarter-over-quarter primarily due to favourable changes in gas and power contract positions; decreased year-over-year primarily due to the reversal of 2013 mark-to-market losses in 2014		34.3		(50.3)
Other		(3.1)		(1.2)
Contribution to consolidated net income – 2015	**$**	**27.5**	**$**	**59.2**

A significant portion of earnings are exposed to foreign exchange fluctuations thereby affecting CAD dollar contribution to net earnings. The impact of a stronger USD quarter-over-quarter increased earnings in CAD dollars by $5.3 million in Q3 2015 compared to Q3 2014. Year-to-date in 2015 the impact of a stronger USD increased earnings in CAD dollars by $8.5 million compared to the same period in 2014.

Energy Services

Adjusted EBITDA

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

For the millions of Canadian dollars		Three months ended September 30				Nine months ended September 30		
		2015		2014		**2015**		2014
Trading and marketing margin	**$**	**5.2**	$	9.2	**$**	**46.9**	$	101.7
OM&G		**3.7**		3.3		**13.5**		19.8
Other income (expenses), net		**1.7**		1.1		**4.8**		1.8
Adjusted EBITDA	**$**	**3.2**	$	7.0	**$**	**38.2**	$	83.7

Trading and Marketing Margin

Trading and marketing margin decreased $4.0 million to $5.2 million in Q3 2015 compared to $9.2 million in Q3 2014. This reflects cooler temperatures and reduced gas transmission constraints within Emera Energy's markets, in part from reduced pipeline maintenance activities which resulted in lower gas prices, reduced volatility and fewer optimization opportunities.

Year-to-date, trading and marketing margin decreased $54.8 million to $46.9 million in 2015 compared to $101.7 million during the same period in 2014. This reflects a return to more normal market conditions following a particularly strong Q1 2014, which was the result of the combined impact of cold weather, infrastructure constraints and other market factors.

Trading and Marketing – OM&G

OM&G increased $0.4 million to $3.7 million in Q3 2015 from $3.3 million in Q3 2014. Year-over-year, OM&G decreased $6.3 million to $13.5 million in 2015 compared to $19.8 million during the same period in 2014 primarily due to decreased performance-based compensation resulting from decreased trading and marketing margins.

Generation

Adjusted EBITDA

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

For the millions of Canadian dollars						Three months ended September 30
	New England		Maritime Canada		Total	
	2015	2014	**2015**	2014	**2015**	2014
Energy sales	**$ 66.8**	$ 53.2	**$ 14.7**	$ 16.1	**$ 81.5**	$ 69.3
Capacity and other	**11.3**	8.9	**-**	-	**11.3**	8.9
Electricity sales	**$ 78.1**	$ 62.1	**$ 14.7**	$ 16.1	**$ 92.8**	$ 78.2
Non-regulated fuel for generation and purchased power	**44.8**	40.7	**6.6**	8.1	**51.4**	48.8
Non-regulated electric margin	**33.3**	21.4	**8.1**	8.0	**41.4**	29.4
OM&G	**9.0**	8.1	**5.2**	5.2	**14.2**	13.3
Other income (expenses), net	**-**	-	**0.4**	0.5	**0.4**	0.5
Adjusted EBITDA	**$ 24.3**	$ 13.3	**$ 3.3**	$ 3.3	**$ 27.6**	$ 16.6

For the millions of Canadian dollars						Nine months ended September 30
	New England		Maritime Canada		Total	
	2015	2014	**2015**	2014	**2015**	2014
Energy sales	**$ 303.2**	$ 309.8	**$ 68.4**	$ 83.6	**$ 371.6**	$ 393.4
Capacity and other	**31.8**	24.9	**-**	-	**31.8**	24.9
Electricity sales	**$ 335.0**	$ 334.7	**$ 68.4**	$ 83.6	**$ 403.4**	$ 418.3
Non-regulated fuel for generation and purchased power	**204.6**	266.9	**41.3**	58.2	**245.9**	325.1
Non-regulated electric margin	**130.4**	67.8	**27.1**	25.4	**157.5**	93.2
OM&G	**28.5**	26.1	**15.0**	18.3	**43.5**	44.4
Other income (expenses), net	**1.3**	-	**(0.6)**	0.3	**0.7**	0.3
Adjusted EBITDA	**$ 103.2**	$ 41.7	**$ 11.5**	$ 7.4	**$ 114.7**	$ 49.1

Adjusted EBITDA increased $11.0 million to $27.6 million in Q3 2015 from $16.6 million in Q3 2014 and year-to-date increased $65.6 million to $114.7 million in 2015 from $49.1 million for the same period in 2014. This is primarily due to higher margins realized in the New England facilities, reflecting favourable short-term economic hedges, favourable pricing and reduced operating costs at Bayside and the strengthening USD.

Operating Statistics

For the	Three months ended September 30					
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2015	2014	**2015**	2014	**2015**	2014
New England	**1,295**	1,150	**98.9%**	84.3%	**53.8%**	49.5%
Maritime Canada	**376**	392	**89.5%**	86.4%	**54.4%**	56.8%
Total	**1,671**	1,542	**96.8%**	84.8%	**53.9%**	51.2%

For the	Nine months ended September 30					
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2015	2014	**2015**	2014	**2015**	2014
New England	**3,583**	3,598	**96.1%**	85.7%	**50.7%**	52.3%
Maritime Canada	**1,282**	1,386	**91.8%**	90.2%	**62.4%**	67.8%
Total	**4,865**	4,984	**95.2%**	86.7%	**53.4%**	55.8%

(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.

Sales volumes and net capacity factor increased quarter-over-quarter primarily due to the impact of a shutdown and plant upgrade at the Bridgeport facility in 2014; year-over-year decrease in sales volumes and net capacity factor primarily due to weaker market conditions, resulting largely from weather.

Upgrades, including new gas turbine rotor and improved combustion system at the Bridgeport facility, completed in Q2 2015, added 20 MW of capacity, bringing the total to 560 MW. Availability has increased at the New England plants due to significant reliability and performance-based investment in 2014.

The New England generating facilities sell into price based competitive markets. The primary reason that the overall capacity factor is lower for New England facilities as compared to the Maritime facilities is the Rumford Power Plant, in particular, expectedly operates with a capacity factor of approximately 20 per cent, reflecting current electricity and gas supply price dynamics in its markets.

Equity Investments

Adjusted income from equity investments

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Bear Swamp	**$ 7.4**	$ 10.3	**$ 21.3**	$ 16.8
NWP	**-**	(4.9)	**1.9**	(6.1)
Adjusted income from equity investments	**$ 7.4**	$ 5.4	**$ 23.2**	$ 10.7

Adjusted income from equity investments increased $2.0 million to $7.4 million in Q3 2015 compared to $5.4 million in Q3 2014 primarily due to NWP losses recorded in 2014, not repeated in 2015 because of sale of NWP in January 2015, partially offset by lower forward reserve revenues and pricing at Bear Swamp. Year-to-date, adjusted income from equity investments increased $12.5 million to $23.2 million in 2015 compared to $10.7 million during the same period in 2014. This is primarily due to a resupply of contracted power sales in Bear Swamp in Q3 2015 that were not delivered in 2014 due to transmission line outages and NWP losses recorded in 2014.

CORPORATE AND OTHER

Corporate

Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, corporate business development, corporate governance, internal audit, investor relations, risk management, insurance, acquisition related costs and certain 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 consolidated 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 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 20.8 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 distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American-based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate-regulated electric transmission and natural gas pipeline systems in the United States and Canada. 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 September 30, 2015, Emera owned 50.1 million common shares and 12.024 million outstanding subscription receipts at an average conversion price of $9.19, which if converted results in Emera's interest increasing to 24.8 per cent.

- 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 49.6 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. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017.

- Emera's 3.3 per cent investment in Open Hydro is accounted for on the cost basis.

- Other investments.

Review of 2015

Corporate and Other

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Intercompany revenue (1)	**$ 9.7**	$ 6.7	**$ 24.3**	$ 19.2
Non-regulated operating revenue	**12.3**	15.6	**30.2**	32.6
Non-regulated direct costs	**12.0**	14.3	**32.5**	31.7
Operating, maintenance and general	**48.5**	10.2	**71.4**	29.4
Depreciation and amortization	**0.4**	0.6	**1.0**	1.8
Total operating expenses	**60.9**	25.1	**104.9**	62.9
Income (loss) from operations	**(38.9)**	(2.8)	**(50.4)**	(11.1)
Income (loss) from equity investments	**10.0**	18.5	**35.8**	34.7
Other income (expenses), net	**0.8**	(0.6)	**0.7**	3.3
Interest expense	**6.4**	7.7	**18.6**	24.6
Income (loss) before provision for income taxes	**(34.5)**	7.4	**(32.5)**	2.3
Income tax expense (recovery)	**(14.2)**	(5.7)	**(24.6)**	(15.4)
Preferred stock dividends	**14.8**	15.0	**30.3**	26.2
Contribution to consolidated net income	**$ (35.1)**	$ (1.9)	**$ (38.2)**	$ (8.5)
Contribution to consolidated earnings per common share – basic	**$ (0.24)**	$ (0.01)	**$ (0.26)**	$ (0.06)
EBITDA	**$ (27.7)**	$ 15.7	**$ (12.9)**	$ 28.7

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

Corporate and Other contribution to consolidated net income decreased $33.2 million to $(35.1) million in Q3 2015 compared to $(1.9) million in Q3 2014. Year-to-date, Corporate and Other contribution to consolidated net income decreased $29.7 million to $(38.2) million in 2015 compared to $(8.5) million during the same period in 2014. Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2014	**$ (1.9)**	**$ (8.5)**
Increased intercompany revenue due to the issuance of a loan to Emera Energy Generation, partially offset by the repayment of an intercompany loan from Brunswick Pipeline	3.0	5.1
Increased OM&G primarily due to acquisition related costs related to the pending TECO Energy acquisition, higher deferred compensation and other business development costs	(38.3)	(42.0)
Income from equity investments – see Income from Equity Investments section below	(8.5)	1.1
Increased other income, net quarter-over-quarter primarily due to foreign exchange gains, partially offset by losses incurred in Emera Reinsurance from Tropical Storm Erika; year-over-year this increase was offset by the recognition of NSPML as equity investment in Q2 2014	1.4	(2.6)
Decreased interest expense primarily due to maturity of long-term debt in Q3 2014	1.3	6.0
Decreased income tax expense primarily due to decreased income before provision for income taxes	8.5	9.2
Increased preferred stock dividends year-over-year primarily due to issuance of preferred shares in Q2 2014	0.2	(4.1)
Other	(0.8)	(2.4)
Contribution to consolidated net income – 2015	**$ (35.1)**	**$ (38.2)**

Acquisition Related Costs

Emera incurred acquisition related costs of $20.1 million after-tax ($0.14 per common share) related to its pending acquisition of TECO Energy. These costs included $30.5 million recorded in “Operating, maintenance and general” and $0.6 million recorded in “Interest expense, net”, partially offset by $2.8 million recorded as a foreign exchange gain recorded in “Other income (expenses), net” and an income tax recovery of $8.2 million recorded in “Income tax expense (recovery)” in Emera’s Consolidated Statements of Income. Further information on the pending acquisition is in the Developments section of the MD&A.

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
APUC	**$ 3.8**	$ 13.6	**$ 18.9**	$ 24.8
NSPML	**3.8**	3.2	**11.1**	5.1
LIL	**2.4**	1.7	**5.8**	4.8
	$ 10.0	$ 18.5	**$ 35.8**	$ 34.7

Income from equity investments decreased $8.5 million to $10.0 million in Q3 2015 compared to $18.5 million in Q3 2014. Year-to-date, income from equity investments increased $1.1 million to $35.8 million in 2015 compared to $34.7 million during the same period in 2014. Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Income from equity investments – 2014	**$ 18.5**	**$ 34.7**
APUC – Primarily due to a pre-tax gain on dilution of $10.8 million in 2014, partially offset by higher equity earnings in 2015	(9.8)	(5.9)
NSPML – Recognition of the AFUDC earnings of NSPML as income from equity investment effective Q2 2014	0.6	6.0
LIL – Increase in investment	0.7	1.0
Income from equity investments – 2015	**$ 10.0**	**$ 35.8**

NSPML has cumulatively invested $623.6 million, including $66.6 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested a total of $141.5 million in equity, with the remaining costs being funded with debt, which 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 will be used to fund project costs until the Project's debt to equity ratio reaches 70 per cent to 30 per cent respectively, which is expected to occur in Q4 2015.

Project to date, ENL has invested $152 million, including $17.5 million of equity earnings, in LIL. 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 Emera's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries maintain solid credit metrics and are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the nine months ended September 30, 2015 and 2014 include:

millions of Canadian dollars	**2015**	2014	$ Change
Cash and cash equivalents, beginning of period	**$ 221.1**	$ 100.8	$ 120.3
Provided by (used in):			
Operating cash flow before change in working capital	**603.8**	564.3	39.5
Change in working capital	**(20.0)**	21.0	(41.0)
Operating activities	**583.8**	585.3	(1.5)
Investing activities	**(122.2)**	(403.4)	281.2
Financing activities	**75.7**	(5.8)	81.5
Effect of exchange rate changes on cash and cash equivalents	**36.6**	4.1	32.5
Cash and cash equivalents, end of period	**$ 795.0**	$ 281.0	$ 514.0

Operating Cash Flows

Refer to Consolidated Income Statement Highlights for details.

Investing Cash Flows

Net cash used in investing activities decreased $281.2 million to $122.2 million for the nine months ended September 30, 2015 compared to $403.4 million for the same period in 2014. The decrease was primarily due to proceeds from the sale of NWP in 2015 and increased investments in NSPML and M&NP in 2014. This is partially offset by increased capital spend at the New England Gas Generating Facilities.

Capital expenditures for the nine months ended September 30, 2015, including AFUDC and net of proceeds from disposal of assets, were $320 million compared to $268 million during the same period in 2014 primarily due to increased capital spending at Emera Energy. Details of the capital spend are shown below:

- $180 million at NSPI (2014 – $175 million);
- $58 million at Emera Maine (2014 – $52 million);
- $26 million at Emera Caribbean (2014 – $22 million);
- $49 million at Emera Energy (2014 – $11 million);
- $7 million in Corporate and Other (2014 – $8 million)

Financing Cash Flows

Net cash provided by financing activities increased $81.5 million to $75.7 million for the nine months ended September 30, 2015 compared to cash used in financing activities of $5.8 million for the same period in 2014. The increase was primarily due to the proceeds of convertible debentures represented by instalment receipts related to the pending acquisition of TECO Energy, net of issuance costs, of $592.5 million and the proceeds of the long-term debt issuance by Brunswick Pipeline and NSPI. This was partially offset by repayment of debt in 2015 and the issuance of common and preferred stock in Q1 2014.

Contractual Obligations

As at September 30, 2015, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars		2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt	$	75.4 $	272.9 $	49.4 $	22.9 $	690.2 $	2,661.9 $	3,772.7
Purchased power (1)		52.9	219.9	230.4	204.9	199.7	2,545.2	3,453.0
Coal, biomass, oil and natural gas supply		50.8	164.5	71.7	0.5	-	-	287.5
Pension and post-retirement obligations (2)		4.2	14.3	13.9	14.0	14.1	806.1	866.6
Asset retirement obligations		0.2	3.6	1.9	1.9	1.9	325.4	334.9
Interest payment obligations (3)		53.5	182.8	173.8	171.5	164.4	2,381.7	3,127.7
Convertible debentures represented by instalment receipts (4)		-	632.7	-	-	-	-	632.7
Interest obligations on the first instalment of convertible debentures represented by instalment receipts (4)		10.0	66.0	-	-	-	-	76.0
Transportation (5)		33.3	104.6	61.8	47.0	24.9	106.1	377.7
Long-term service agreements (6)		21.6	53.1	42.8	31.7	53.3	218.3	420.8
Capital projects		49.9	36.6	5.6	0.1	-	-	92.2
Equity investment commitments (7)		113.1	330.2	159.3	-	-	-	602.6
Leases and other (8)		10.1	11.9	11.3	9.2	8.7	33.5	84.7
	$	475.0 $	2,093.1 $	821.9 $	503.7 $	1,157.2 $	9,078.2 $	14,129.1

(1) Purchased power: annual requirement to purchase 20 - 100 per cent of electricity production from independent power producers over varying contract lengths up to 25 years.

(2) Pension and post-retirement obligations: Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2014. Credited service and earnings are assumed to be crystallized as at December 31, 2014. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over as at December 31, 2014 to be eligible. As the defined benefit pension plans currently undergoes regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(3) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at September 30, 2015. The hedged rate was used to determine Brunswick Pipeline's interest payment obligations.

(4) Convertible debentures: On September 28, 2015, to finance a portion of the pending acquisition of TECO Energy, Emera completed the sale of $1.9 billion principal amount of 4 per cent convertible unsecured subordinated debentures. The table above shows the obligations as a result of this Debenture Offering. Subsequent to September 30, 2015 the over-allotment option was exercised and $285 million in additional Debentures were sold. The instalment receipts related to the over-allotment option will represent an additional obligation of $94.9 million in 2016. The interest obligation associated with the over-allotment option will be $1.5 million in 2015 and $9.9 million in 2016. Further information on the Debenture Offering is in the Developments section.

(5) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.

(6) Long-term service agreements: 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 LIL 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 amount as the projects advance through construction.

(8) Leases: 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 consolidation 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 as discussed in 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 September 30, 2015, 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 (1)	June 2020 – Revolver	$ 700	$ 262	$ 438
NSPI – Operating credit facility	June 2019 – Revolver	500	71	429
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	27	53
Other – in USD – Operating credit facilities	Various	32	-	32

(1) Extended to June 2020 on August 21, 2015.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at September 30, 2015.

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

As at September 30, 2015, approximately 91 per cent of Emera's consolidated debt position is fixed rate in nature, with an average term to maturity of approximately 17 years. Emera's scheduled maturities for debt over the next five years are expected to be on average $188 million annually.

Emera's future liquidity and capital needs, not including the capital needs to fund the TECO Energy acquisition, will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, as well as 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 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.

Credit Ratings

Emera

On March 11, 2015, DBRS removed Emera from "Under Review with Developing Implications" following the closing of the Brunswick Pipeline financing and the sale of NWP. On the same date, DBRS confirmed Emera's Issuer Rating and Medium-Term Notes rating at BBB (high) and the Cumulative Preferred Shares Rating at Pfd-3 (high), all with Stable trends.

On September 4, 2015, following the announcement of the TECO Energy acquisition, DBRS placed the ratings of Emera 'Under Review with Developing Implications'. The rating actions reflect DBRS's view that while the TECO Energy acquisition would have a relatively neutral impact on Emera's business risk assessment, the impact on the financial risk assessment was at the time of the ratings actions uncertain as Emera's financing plan had not been finalized. DBRS indicated that it will further review Emera's financing plan when it is finalized.

On September 8, 2015, Standard and Poor's ("S&P") revised its outlook on Emera to negative from stable, while affirming all ratings on Emera, including its 'BBB+' long-term corporate rating. S&P indicated that the negative outlook is primarily associated with the Debentures and the risk that they will not be converted into equity upon successful close of the acquisition. S&P could revise its outlook to stable within a two-year outlook period, if the Debentures are successfully converted.

NSPI

On September 8, 2015, S&P affirmed all ratings on Emera and NSPI and revised Emera's outlook to negative from stable. The outlook revision followed Emera's announcement of the proposed acquisition of TECO Energy. Per S&P's group rating methodology criteria, NSPI is subject to Emera's revised outlook.

Guarantees and Letters of Credit

Emera has entered into the following standby letters of credit since its year end disclosure at December 31, 2014:

- A standby letter of credit was issued to secure the obligations of Emera Reinsurance Limited under reinsurance agreements. The letter of credit expires in February 2016. The amount committed as at September 30, 2015 was $2.0 million USD.

- NSPI has standby letters of credit in the amount of $0.8 million, the majority of which cover an Abandonment Reclamation Agreement related to a lease with the Province of Nova Scotia. These letters of credit have a one-year term and are renewed annually as required.

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 the absolute 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 U.S., major hydro developments in Newfoundland and Labrador, and 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 too does the availability and demand for affordable new tools 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 advances such as grid modernization or 'smart grid' initiatives 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 an expectation on the part of customers 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. This, in turn, raises new issues related to the role of the utility, and the appropriate allocation of existing infrastructure and transmission, generation and distribution costs.

Taken together, 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.

The pending TECO Energy acquisition is expected to result in acquisition costs in 2015/2016 and is expected to be accretive to Emera's EPS by approximately 5 per cent in the first full year following its completion (2017), excluding acquisition related costs, growing to more than 10 per cent by the third full year (2019), assuming a stable currency environment.

The operations of TECO Energy are conducted in US dollars. Following the acquisition, the consolidated net income and cash flows of Emera 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 equity thickness 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.

NSPI anticipates earning within its allowed ROE range in 2015 and expects its rate base to remain stable and earnings to grow modestly compared to 2014. 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. NSPI is placing an emphasis on providing rate stability for customers over the next several years through a focused effort on operating costs, productivity levels and service improvements.

On November 10, 2015, NSPI announced it does not plan to file a general rate application related to electricity rates for 2016.

Capital expenditures for 2015, including AFUDC are forecasted to be $259 million (2014 - $274 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 2015 ROE is expected to be consistent with prior years and 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 New England markets. As part of this agreement, Emera Maine and Central Maine Power Company are intending to respond to a request for proposal from Massachusetts, Connecticut and Rhode Island, which was recently reviewed by regulators and was released on November 12, 2015. The demand for this renewable energy is growing as a result of increasing renewable portfolio requirements of the southern New England states.

Future earnings will generally reflect the impact of transmission rate decisions by the FERC. Emera Maine has fully reserved for the refunds required as a result of a FERC decision on the allowed ROE set at 10.57 per cent.

In 2015, Emera Maine expects to invest approximately $84 million (2014 - $85 million actual), including approximately $20 million for major transmission projects.

Emera Caribbean

Earnings from Emera Caribbean are most directly impacted by the combined impacts of the range of rates of return on equity and rate base approved by their regulators, capital structure, the 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 economy of Grand Bahamas is highly correlated to the United States economy, and in 2014, exhibited improved economic growth primarily in the industrial sector. Year-to-date in 2015, industrial and residential sales have grown in relation to 2014. GBPC's regulatory rate structure requires base rates to be set every three years with the next base rate change scheduled for January 2016. Thus, GBPC filed a rate request in Q3 2015, with a decision expected by December 1, 2015.

The Barbados economy remains challenged, with growth of approximately 1 per cent forecast for 2015, resulting in continuing pressure on its electric sales volumes. 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. BLPC recognized the need to reduce costs in the business to stabilize future rates to customers.

Tropical Storm Erika affected the island of Dominica on August 27, 2015 and as a result, weaker economic growth is expected to affect sales into 2016. In connection with its pending rate case, Domlec made a preliminary filing in 2014 requesting that a weighted average cost of capital rate of 11.6 per cent be used for rate making purposes. In Q2 2015, the IRC set a cost of capital rate of 8.56 per cent, which Domlec appealed unsuccessfully to the IRC. Domlec made a further appeal to the Dominican court. The rate filing and rate case proceedings will begin after the cost of capital is determined. The cost of capital rate hearing has been delayed, with no new hearing date yet determined due to Tropical Storm Erika.

There are growth opportunities for Emera in this market centered on creating and capturing opportunities for cleaner fuels and renewable energy generation. As part of this initiative, construction of a 10 MW solar facility is expected to begin in Barbados in Q4 2015 and is scheduled for completion in the first half of 2016. In addition, an application to export natural gas to counties with no free trade agreement with the United States, specifically The Bahamas, was filed with the US Department of Energy and approval was received on October 20, 2015, granting long-term multi contract authorization for Emera to export natural gas, by vessel, in the amount of 8 million standard cubic feet per day ("mmscfd"). This complements the authorization received in April 2015 to export up to 25 mmscfd to countries which have a free trade agreement with the United States.

Overall, Emera Caribbean earnings are expected to be consistent with prior years.

Emera Caribbean plans to invest approximately $54 million in capital programs in 2015 (2014 - $30 million actual).

Pipelines

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

Pipelines' 2015 earnings are expected to be consistent with prior years.

Emera Energy

Energy Services

Emera Energy Services, which is Emera Energy's trading and marketing 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 factors, can provide higher levels of margin opportunity. The past three years have seen favourable market conditions in this regard within Emera Energy's key markets, with Q4 2013 and Q1 2014, in particular, evidencing unprecedented market volatility. This was a result of the combined impacts of cold weather, constraints in the supply or transportation of natural gas, and other market factors, and contributed to very strong earnings from trading and marketing in those periods.

2015 has seen a return to lower market volatility and pricing, and a resulting decrease in trading and marketing earnings compared to 2014. In addition to capitalizing on volatility-driven market opportunities, the business 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 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.

Generation

Earnings from Emera Energy Generation's assets are largely dependent on market conditions and 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. 2015 earnings from Emera Energy generating assets are expected to be higher than 2014, reflecting the impact of short-term economic hedges of gas supply costs and electricity sales prices that are delivering higher margins.

In addition to energy 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, the largest is the FCM. FCM prices are determined through an auction process held annually, three years in advance, providing revenue visibility to 2019, 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

(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

In 2015, Emera Energy expects to invest approximately $67 million (2014 - $63 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 2015/2016 will include acquisition costs related to the pending TECO Energy acquisition, the timing of equity investments in the Maritime Link Project and the Labrador-Island Link, project-based construction services activity by Emera Utility Services, growth and fluctuations in APUC earnings (which Emera accounts one quarter after APUC reports such earnings), corporate financing and other corporate activities.

Corporate's contribution to consolidated net income is expected to be lower in 2015 primarily due to acquisition costs and associated financing initiatives related to the pending TECO Energy acquisition.

Corporate and Other plan to invest approximately $10 million in capital programs in 2015 (2014 - $10 million actual).

ENL

Through its subsidiary, NSP Maritime Link Inc., ENL has cumulatively invested $623.6 million, including $66.6 million of AFUDC, in the development of the Maritime Link Project. To the end of Q3 2015, ENL has invested a total of $141.5 million in equity, with the remaining costs being funded with debt, which 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 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 April 2014 will be used to fund project costs until the Project's debt to equity ratio reaches 70 per cent to 30 per cent respectively, which is expected to occur in Q4 2015. From that point forward, project costs will be funded with debt and equity at a 70 per cent to 30 per cent ratio. Equity contributions for 2015 are forecasted to be approximately $9 million.

Maritime Link Project forecasted equity contributions for 2016 and 2017 are $159 million each year, with total equity for the Project estimated to be $469 million.

ENL is a partner with Nalcor Energy in LIL, which is currently estimated at approximately $3.1 billion. To Q3 2015, ENL has invested $152 million, including $17.5 million of equity earnings in LIL. Equity earnings are being recorded based on an annual rate of 8.8 per cent of the equity invested. The rate is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities. ENL has an ongoing equity investment opportunity in LIL. Future earnings are dependent upon the timing of additional equity investments. The expected total equity contribution for 2015 for LIL, including the equity contribution of $66.7 million to the end of Q3 2015, is $171 million.

LIL forecasted equity contributions for 2016 are $171 million, with total equity for the Project estimated to be $410 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 associated and other related companies on terms similar to those offered to non-related parties.

If these transactions are eliminated on consolidation, they are not disclosed as related party transactions. Below are transactions between Emera and its associated companies that are not eliminated on consolidation:

For the millions of Canadian dollars			Three months ended September 30		Nine months ended September 30	
			2015	2014	**2015**	2014
	Nature of Service	**Presentation**				
Sales:						
Emera Utility Services	Maintenance and construction services	Operating revenue – non-regulated	**$ 6.7**	$ 5.8	**$ 15.7**	$ 11.5
Emera Energy	Net sale of natural gas and sale of power	Operating revenue – non-regulated	**4.0**	4.5	**11.6**	10.6
Emera Energy	Hedging services	Operating revenue – non-regulated and interest expense, net	**4.8**	-	**11.5**	-
EUS Bahamas	Construction, operations management and engineering services	Operating revenue – non-regulated	**2.7**	2.8	**7.5**	6.9
Emera Energy	Sale of natural gas and transportation (3)	Operating revenue – non-regulated	**-**	0.2	**1.6**	4.3
Emera Energy	Energy management services (1)	Operating revenue – non-regulated	**-**	-	**-**	0.2
Emera Maine	Transmission capacity (1)	Operating revenue – regulated	**-**	0.2	**0.3**	0.8
Purchases:						
NSPI	Construction services	Property, plant and equipment	**6.7**	4.9	**14.0**	9.7
NSPI	Net purchase of natural gas and purchase of power	Regulated fuel for generation and purchased power	**4.0**	4.5	**11.6**	10.6
GBPC	Hedging services	Regulated fuel for generation and purchased power and OM&G	**4.8**	-	**11.5**	-
GBPC	Maintenance services	OM&G	**2.7**	2.8	**7.2**	6.3
NSPI	Natural gas transportation capacity (2)	Regulated fuel for generation and purchased power	**1.7**	1.0	**3.7**	3.2
NSPI	Maintenance services	OM&G	**0.1**	0.9	**1.8**	1.8
GBPC	Construction services	Property, plant and equipment	**-**	-	**0.3**	0.6
Emera Maine	Purchase of power (1)	Regulated fuel for generation and purchased power	**-**	0.4	**0.3**	1.4
Emera Energy	Natural gas transportation capacity (2)	Operating revenue – non-regulated	**(5.5)**	(5.5)	**(16.8)**	(18.6)

(1) Transactions with NWP which was a related party accounted for under the equity method until its sale on January 29, 2015.

(2) Transactions with M&NP, a related party accounted for under the equity method.

(3) Transactions with a subsidiary of APUC, a related party accounted for under the equity method.

Amounts due (to) from Emera and its equity investments are summarized in the following table:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Due from related parties:		
NSPML – current	**$ 1.4**	$ 3.5
M&NP – loan receivable – long-term	**2.5**	2.5
Due to related parties:		
M&NP – current	**$ (1.7)**	$ (1.6)
Net due from (to) related parties	**$ 2.2**	$ 4.4

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, 2014.

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2015**	December 31 2014
Derivative instrument assets (current and other assets)	**$ 19.2**	$ 23.0
Derivative instrument liabilities (current and long-term liabilities)	**(40.3)**	(19.2)
Net derivative instrument assets (liabilities)	**$ (21.1)**	$ 3.8

Hedging Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Operating revenues – regulated	**$ (2.6)**	$ (0.6)	**$ (6.3)**	$ (2.3)
Non-regulated fuel for generation and purchased power	**(1.1)**	(1.9)	**3.9**	1.9
Income from equity investments	**(0.2)**	(0.2)	**(0.5)**	(0.5)
Effective net gains (losses)	**$ (3.9)**	$ (2.7)	**$ (2.9)**	$ (0.9)

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

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Non-regulated fuel for generation and purchased power	**$ 0.2**	$ 2.4	**$ (0.1)**	$ 2.7
Ineffective gains (losses)	**$ 0.2**	$ 2.4	**$ (0.1)**	$ 2.7

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2015**	December 31 2014
Derivative instrument assets (current and other assets)	**$ 203.3**	$ 97.7
Regulatory assets (current and other assets)	**54.5**	43.6
Derivative instrument liabilities (current and long-term liabilities)	**(51.4)**	(40.3)
Regulatory liabilities (current and long-term liabilities)	**(203.3)**	(97.7)
Net asset (liability)	**$ 3.1**	$ 3.3

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Regulated fuel for generation and purchased power (1)	**$ 9.8**	$ 2.2	**$ 23.6**	$ 19.8
Net gains (losses)	**$ 9.8**	$ 2.2	**$ 23.6**	$ 19.8

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

Held-for-trading Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**September 30 2015**		December 31 2014
Derivative instruments assets (current and other assets)	**$**	**92.1**	$	107.8
Derivative instruments liabilities (current and long-term liabilities)		**(131.5)**		(145.3)
Net derivative instrument assets (liabilities)	**$**	**(39.4)**	$	(37.5)

Held-for-trading Items Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended September 30				Nine months ended September 30		
		2015		2014		**2015**		2014
Operating revenue - non-regulated	**$**	**44.3**	$	4.0	**$**	**116.4**	$	192.3
Non-regulated fuel for purchased power		**(4.1)**		(2.4)		**(8.0)**		(5.4)
Net gains (losses)	**$**	**40.2**	$	1.6	**$**	**108.4**	$	186.9

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**September 30 2015**		December 31 2014
Derivative instrument liabilities (current and long-term liabilities)	**$**	**(3.1)**	$	-
Net derivative instrument assets (liabilities)	**$**	**(3.1)**	$	-

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended September 30				Nine months ended September 30		
		2015		2014		**2015**		2014
Interest expense, net	**$**	**(1.2)**	$	-	**$**	**(3.1)**	$	-
Total gains (losses)	**$**	**(1.2)**	$	-	**$**	**(3.1)**	$	-

Business Risks

The following changes in the Company's significant business risks occurred during Q3 2015 and year-to-date in 2015 from those disclosed in the MD&A for the year ended December 31, 2014.

Completion of the Acquisition of TECO Energy

The closing of the acquisition of TECO Energy is subject to the commercial risks associated with a publicly owned regulated utility acquisition per the terms negotiated in the acquisition agreement. The acquisition is subject to approval by TECO Energy shareholder and certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Federal Energy Regulatory Commission, the Committee on Foreign Investment in the United States, compliance with any applicable requirement under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the satisfaction of closing conditions.

Failure to obtain the required approvals or satisfy or waive the conditions contained in the acquisition agreement may result in the termination of the acquisition agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Emera will complete the acquisition in the timeframe or on the basis described herein, if at all. The termination of the acquisition agreement may have a negative effect on the price of the instalment receipts, the Debentures and the common shares and will result in the redemption of the Debentures. If the closing of the acquisition does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence.

A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Company's ability to complete the acquisition and on the Company's or TECO Energy's business, financial condition or results of operations. In addition, in the event that such regulatory agencies impose unfavourable terms and/or conditions on Emera or any TECO Energy utility (including the requirement to sell or divest of certain assets or limitations on the future conduct of the individual or combined entities), the Company would still be required to complete the transaction on the terms set forth in the acquisition agreement. Emera intends to complete the acquisition as soon as practicable after obtaining the required TECO Energy shareholder approval and regulatory approvals and satisfaction of the other required closing conditions.

TECO Energy is a public company and its directors owe fiduciary duties to TECO Energy shareholders (and other stakeholders) which may require them to consider competing offers to purchase the common stock of TECO Energy as alternatives to the acquisition. The acquisition agreement preserves the ability of the directors of TECO Energy to accept an alternative or competing offer in certain circumstances if such offer constitutes a superior proposal. If a superior proposal to acquire TECO Energy is made, and if the superior proposal results in TECO Energy's Board of Directors making an adverse recommendation change, if requested by Emera, TECO Energy and its representatives are required to negotiate in good faith with Emera regarding any revisions to the acquisition agreement committed to in writing by Emera, which could result in an increase to the cash purchase of the acquisition or to other terms and conditions of the acquisition.

Emera expects the pending acquisition of TECO Energy will provide benefits to the Company, including that the acquisition will be accretive to Emera's EPS by approximately five per cent in the first full year following its completion (2017), excluding acquisition related expenses, growing to more than 10 per cent by the third full year (2019), assuming a stable currency environment. In addition, the availability of net operating loss carry-forwards and alternative minimum tax credits, if utilized, are expected to provide significant accretion to Emera's cash position. However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated by the Company. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Company. The challenge of combining previously independent businesses makes evaluating the Company's business and future financial prospects difficult. The past financial performance of the Company may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the acquisition may include terms which could have an adverse effect on the Company's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the acquisition may impact the financial performance of the Company, the price of its common shares and the ability of Emera to continue to pay dividends on its common shares at current levels or at all. The declaration of dividends by the Company is at the discretion of the Board of Directors.

In addition to the potential liability for damages for breach of the acquisition agreement by Emera, if (i) the acquisition agreement is terminated by either party due to a failure to obtain the required regulatory approvals by the end date specified in the acquisition agreement, or because there is a final and non-appealable legal restraint that relates to the required regulatory approvals, or if TECO Energy terminates the acquisition agreement based on a failure by Emera to perform its agreements with respect to the receipt of the required regulatory approvals, and, in each case, at the time of such termination the TECO Energy shareholder approval shall have been obtained and the other closing conditions on behalf of Emera shall have been satisfied or waived (except for those conditions, that by their nature, are to be satisfied at the closing of the acquisition, but which conditions would be satisfied, or would be capable of being satisfied, if the closing of the Acquisition were to occur on the date of such termination and those conditions that have not been satisfied as a result of a breach of the acquisition agreement by Emera), or (ii) TECO Energy terminates the acquisition agreement in the event that all applicable closing conditions have been satisfied or waived and Emera fails to close the acquisition because of a failure of any person or entity to provide acquisition financing, then Emera will be obligated to pay to TECO Energy a fee of $326.9 million USD in cash.

For the purpose of financing the pending acquisition, Emera completed a $2.185 billion Debenture Offering in September and October 2015, including the exercise of an over-allotment. The Company also obtained a commitment letter for an aggregate of $6.5 billion USD non-revolving credit facilities. On October 16, 2015, Emera permanently reduced the USD bridge facility 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 commitment of the lenders to enter into the acquisition credit facilities is subject to certain standard conditions, which may result in such facilities becoming unavailable to Emera in certain circumstances. If the acquisition credit facilities become unavailable to Emera, Emera may not be able to complete the acquisition.

Completion of the acquisition is not conditional on the completion of the Debenture Offering by the Company or on the Company obtaining financing on favourable terms or at all. If a material amount due on payment of the final instalment is not paid by holders of instalment receipts and the Company is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Company will not be able to use those proceeds to repay the acquisition credit facilities. As a result, it may take Emera longer than anticipated to repay the acquisition credit facilities which may have a negative impact on the consolidated capitalization of Emera until such time as the acquisition credit facilities have been repaid by Emera in full.

There is no guarantee that alternate sources of funding will be available to Emera or its affiliates at the desired time or at all, or on cost-effective terms. The inability to obtain alternate sources of funding to fund the acquisition or replace the acquisition credit facilities may negatively impact the financial performance of Emera, including the extent to which the acquisition is accretive. In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the acquisition.

Emera expects to incur a number of costs associated with completing the acquisition. The majority of these costs will be non-recurring expenses resulting from the acquisition and will consist of transaction costs related to the acquisition, including costs relating to the financing of the acquisition and obtaining regulatory approvals. Additional unanticipated costs may be incurred relating to the acquisition.

Between September 16, 2015 and October 12, 2015, purported shareholders of TECO Energy filed eleven separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida.

Each complaint alleges that the Board of Directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and seeks to enjoin the merger pursuant to the acquisition agreement. In addition, (i) seven of the complaints allege that TECO Energy, Emera and Emera US Inc. aided and abetted such alleged breaches; (ii) three other complaints allege Emera and Emera US Inc. aided and abetted such alleged breaches; and (iii) one other complaint alleges that Emera aided and abetted such alleged breaches. The complaints were subsequently amended to include allegations that the preliminary proxy statement in relation to the merger filed by TECO Energy on October 6, 2015 fails to disclose certain material information.

The court has scheduled a hearing to be held on November 20, 2015, on the plaintiffs' anticipated motion for a preliminary injunction.

On November 2, 2015, a purported shareholder of TECO Energy filed a complaint styled as a class action lawsuit in the United States District Court for the Middle District of Florida. This complaint alleges that the board of directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition and seeks to enjoin the merger pursuant to the acquisition agreement. In addition, the complaint alleges that Emera and Emera US Inc. aided and abetted such alleged breaches. The complaint further alleges that the preliminary proxy statement and the definitive proxy statement in relation to the merger, filed by TECO Energy on October 6, 2015 and October 22, 2015, respectively, fail to disclose certain material information.

At this time, the outcome of the lawsuits cannot be predicted with any certainty. A preliminary injunction could delay or jeopardize the completion of the transaction, and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Emera believes that the claims asserted against the defendants in the lawsuits are without merit.

Foreign Exchange Risk

The cash consideration for the acquisition is required to be paid in US dollars, while funds raised in the Debenture Offering or any other Canadian dollar offering, which may constitute a significant portion of the funds ultimately used to finance the acquisition, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to either the payment of the final instalment or the close of any Canadian dollar offerings will increase the purchase price translated in Canadian dollars and thereby increase the Canadian dollars required to fund the US dollar purchase price for the acquisition ultimately obtained by Emera.

The proceeds of the first instalment of the Debenture Offering were invested in short-term US dollar investment grade securities. Until the transaction closes, foreign exchange fluctuations could create significant mark-to-market adjustments that may result in volatility in Emera's earnings.

During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the second instalment of the Debenture Offering of the pending TECO Energy acquisition of $1.457 billion. These foreign exchange contracts are economic hedges and do not qualify for hedge accounting. Therefore, all mark-to-market gains and losses will be recognized in net income for the period. Until the hedge settles, foreign exchange fluctuations could create significant mark-to-market adjustments that may result in volatility in Emera's earnings.

In addition, the operations of TECO Energy are conducted in US dollars. Following the acquisition, the consolidated net income and cash flows of Emera will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the acquisition, could negatively impact the Company's net income as reported in Canadian dollars, which could cause a failure to realize all or some of the anticipated benefits of the acquisition.

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 September 30, 2015 disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as those 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 during the period beginning on January 1, 2015 and ending on September 30, 2015, which have materially affected, or are reasonably likely to materially affect 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, asset retirement obligations, capitalized overhead and valuation of derivative instruments. Actual results may differ significantly from these estimates.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Business Combinations – Simplifying the Accounting for Measurement-Period Adjustments, Accounting Standard Update ("ASU") Number ("No.") 2015-16
In September 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-16, Business Combinations – *Simplifying the Accounting for Measurement-Period Adjustments*. The amendment applies to entities that have reported provisional amounts related to a business combination for which the accounting is incomplete by the end of the reporting period and have an adjustment to provisional amounts previously recognized during a later measurement period. Changes in provisional amounts recorded for acquired assets and liabilities are to be adjusted in the period the adjustment is known, with a corresponding adjustment booked to goodwill. The acquirer is no longer required to revise comparative information from prior years for the effect of changes in provisional amounts. The Company has adopted ASU 2015-16 effective September 25, 2015, with no impact on the consolidated financial statements as a result of implementation of this standard.

Future Accounting Pronouncements

Revenue from Contracts with Customers, ASU No. 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. On July 9, 2015, the FASB deferred the effective date by one year. This standard will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Income Statement – Extraordinary and Unusual Items, ASU No. 2015-01
In January 2015, the 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. ASU No. 2015-01 is effective for fiscal years, and interim periods within those fiscal

years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Consolidation, ASU No. 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. All legal entities are subject to re-evaluation under the revised consolidation model. ASU No. 2015-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Interest – Imputation of Interest, No. 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 in 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 by the amendments in the update. ASU No. 2015-03 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. The adoption of this update will result in the reclassification of debt issuance costs from "Other long-term assets" to "Long-term debt" and "Convertible debentures represented by instalment receipts" on the Company's consolidated balance sheets. As at September 30, 2015, debt issuance costs included in "Other long-term assets were $61.2 million (December 31, 2014 - $18.8 million).

In August 2015, the FASB issued ASU 2015-15, *Interest – Imputation of Interest – Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, which clarifies that the guidance in ASU No. 2015-03 does not apply to line-of-credit arrangements. ASU No. 2015-15 permits an entity to defer and present debt issuance costs as an asset and subsequently amortize these costs ratably over the time of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. As at September 30, 2015, debt issuance costs associated with line-of-credit arrangements included in "Other long-term assets" were $3.6 million (December 31, 2014 - $4.1 million) on the Company's consolidated balance sheets.

Compensation – Retirement Benefits, ASU No. 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. ASU No. 2015-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU No. 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, then the customer should 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 should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. ASU No. 2015-05 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Fair Value Measurement Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), ASU No. 2015-07
In May 2015, the FASB issued ASU 2015-07 removing the requirement to categorize and disclose, within the fair value hierarchy, all investments for which fair value is measured using the net asset value per share as a practical expedient. ASU No. 2015-07 is effective beginning after December 15, 2015 and requires retrospective application. The adoption of this update will result in disclosure of all investments for which fair value is measured using the net asset value per share methodology, outside of the fair-value hierarchy. As at September 30, 2015, total investments measured using the net asset value per share were $50.3 million (December 31, 2014 - $31.7 million).

Technical Corrections and Improvements, ASU No. 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 that are not expected to have a significant effect on current accounting practice or create a significant administrative cost. ASU No. 2015-10 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Inventory – Simplifying the Measurement of Inventory, ASU No. 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 No. 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. 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)	**Q3 2015**	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013
Operating revenues	**$ 654.0**	$ 537.0	$ 900.3	$ 792.6	$ 562.4	$ 566.6	$ 1,050.3	$ 594.4
Net income attributable to common shareholders	**35.0**	10.0	160.1	151.2	28.2	24.5	202.8	21.0
Adjusted net income attributable to common shareholders	**23.3**	48.0	171.6	78.5	49.9	44.2	146.6	63.0
Earnings per common share – basic	**0.24**	0.07	1.10	1.05	0.20	0.17	1.43	0.16
Earnings per common share – diluted	**0.24**	0.07	1.09	1.02	0.20	0.17	1.40	0.16
Adjusted earnings per common share – basic	**0.16**	0.33	1.18	0.54	0.35	0.31	1.03	0.47

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 located in northeast 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.