Management's Discussion & Analysis

As at May 6, 2014

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments ("Emera") during the first quarter of 2014 relative to 2013; and its financial position as at March 31, 2014 relative to December 31, 2013. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated unaudited condensed consolidated financial statements and supporting notes as at and for the three months ended March 31, 2014; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2013. 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, revenue and expenses. Emera's rate-regulated subsidiaries include:

Emera Rate-Regulated Subsidiary	**Accounting Policies Approved/Examined By**
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Emera Maine	Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC")
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Dominica Electricity Services Ltd. ("Domlec")	Independent Regulatory Commission, Dominica
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	National Energy Board ("NEB")
NSP Maritime Link Inc. ("NSPML")	UARB

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; 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; 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 on Emera's consolidated subsidiaries and investments, specifically:

- NSPI;
- Emera Maine effective January 1, 2014, as Bangor Hydro Electric Company and Maine Public Service Company merged;
- Emera Caribbean includes BLPC and Domlec and their parent company, Light & Power Holdings Ltd. ("LPH"), GBPC, Emera Utility Services (Bahamas) Limited ("EUS Bahamas") and St. Lucia Electricity Services Limited ("Lucelec");
- Pipelines includes Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") and Maritimes & Northeast Pipeline ("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");
- Corporate and Other includes:
    - Interest revenue on intercompany financings and costs allocated to corporate activities not directly associated with the operations of Emera's consolidated subsidiaries and investments,
    - Emera Utility Services Inc. ("Emera Utility Services"),
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL") and its subsidiaries:
        - NSP Maritime Link Inc.,
        - Labrador-Island Link Limited Partnership ("LIL"),
    - Algonquin Power & Utilities Corp. ("APUC"),
    - Atlantic Hydrogen Inc. ("AHI"),
    - OpenHydro Group Ltd. ("Open Hydro")

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 an energy and services company that owns and invests in electricity generation, transmission and distribution, gas transmission, utility services and provides energy marketing, trading and other energy-related management services.

Emera's strategy is focused on driving profitable growth by investing in its existing and new businesses, improving system reliability, reducing emissions from the generation of electricity, and transmitting that cleaner energy to market. Emera continues to build its existing businesses and leverage assets and capabilities to capitalize on acquisitions and greenfield development opportunities in electric or gas utilities. Emera continues to target a three-to-five year annualized average earnings per share growth rate of 4 to 6 percent.

Emera's business interests are primarily in northeastern North America and the Caribbean. In 2013, approximately 80 percent of Emera's adjusted net income was earned by its rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows to fund dividends and reinvestment.

The energy industry is seasonal in nature for companies like Emera, where seasonal and unseasonal weather patterns, as well as the number and severity of storms, can affect the demand for energy and the 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 period. Therefore, 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 and non-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
Emera Energy adjusted contribution to consolidated net income	Emera Energy contribution to consolidated net income
Emera Energy adjusted income from operations	Emera Energy income from operations
Emera Energy adjusted income before provision for income taxes	Emera Energy income before provision for income taxes
Emera Energy adjusted contribution to consolidated earnings per common share – basic	Emera Energy contribution to consolidated earnings per common share – basic
EBITDA	Income from operations
Adjusted EBITDA	Income from operations
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 and the amortization of transportation capacity recognized as a result of certain trading and marketing transactions. 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 of 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. Management believes excluding the effect of these mark-to-market valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows.

Mark-to-market adjustments are discussed further in the Consolidated Financial Highlights section and the Emera Energy – Review of 2014 section.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2014**	2013
Net income attributable to common shareholders	**$ 202.8**	$ 122.8
After-tax derivative mark-to-market gain (loss)	**$ 56.2**	$ 7.4
Adjusted net income attributable to common shareholders	**$ 146.6**	$ 115.4
Earnings per common share – basic	**$ 1.43**	$ 0.93
Adjusted earnings per common share – basic	**$ 1.03**	$ 0.88

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization "EBITDA" is a non-GAAP financial measure used by Emera. EBITDA is a widely used by investors and lending institutions as an indicator of a company's operating performance prior to accounting for the financing and amortization activities or the taxation of operating results.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to the Adjusted Net Income calculations, this measure represents EBITDA absent the income effect of Emera's mark-to-market adjustments, as previously outlined in the Adjusted Net Income discussion.

The Company's EBITDA and Adjusted EBITDA may not be comparable to other companies' EBITDA measures. This measure is not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance. EBITDA and adjusted EBITDA are discussed further in the Consolidated Financial Review, NSPI, Emera Maine, Emera Caribbean, Pipelines, Emera Energy, and Corporate and Other sections.

EBITDA and Adjusted EBITDA Reconciliation

For the millions of Canadian dollars	Three months ended March 31 **2014**	2013
Net income attributable to common shareholders	**$ 202.8**	$ 122.8
Interest expense, net	**45.3**	42.0
Income tax expense (recovery)	**66.8**	39.4
Depreciation and amortization	**86.4**	74.3
Non-controlling interest in subsidiaries	**5.0**	2.9
Preferred stock dividends	**5.6**	4.2
EBITDA	**411.9**	285.6
Derivative mark-to-market gain (loss)	**80.9**	10.3
Adjusted EBITDA	**$ 331.0**	$ 275.3

Electric Margin

NSPI, Emera Caribbean, Emera Energy

"Electric margin" is a non-GAAP financial measure used to show the amounts NSPI, BLPC, GBPC and Domlec retain to recover their non-fuel costs, as effectively 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.

The companies' electric margin may not be comparable to other companies' electric margin measures. 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 Emera Energy sections.

Significant Items Affecting Earnings

2013

Gains on Exchange of APUC Subscription Receipts to Shares

The following table outlines 2013 subscription receipts which have been converted to shares and their associated after-tax gains that were recorded in 2013:

Underlying Transaction	Quarter Transaction Closed	After-tax gain on conversion of subscription receipts to APUC shares (millions of Canadian dollars)	Earnings Per Common Share Impact
Gamesa – 1/2 of first tranche	Q1 2013	3.6	0.03
Gamesa – second tranche	Q1 2013	7.0	0.05
Completion of California Pacific's rate case – second tranche	Q1 2013	7.5	0.06
Total 2013		**$ 18.1**	**$ 0.14**

Northeast Wind Partners Supplier Settlement

Northeast Wind Partners ("NWP"), a company in which Emera has a 49 percent equity interest, received a settlement of all of its entitlements under various guarantee, warranty and performance obligations of one of its turbine suppliers in Q1 2013. As a result of this settlement, NWP is responsible for future repair costs related to these turbines. Emera's share of the total after-tax net proceeds was $6.8 million ($0.05 per common share), which was included in "Income from equity investments" for the three months ended March 31, 2013.

CONSOLIDATED FINANCIAL REVIEW

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2014**	 2013
Operating revenues	**$ 1,050.3**	$ 638.1
Income from operations	**316.9**	175.7
Net income attributable to common shareholders	**202.8**	122.8
After-tax derivative mark-to-market gain (loss)	**56.2**	7.4
Adjusted net income attributable to common shareholders	**146.6**	115.4
Earnings per common share – basic	**$ 1.43**	$ 0.93
Earnings per common share – diluted	**$ 1.40**	$ 0.92
Adjusted earnings per common share – basic	**$ 1.03**	$ 0.88
Dividends per common share declared	**$ 0.3625**	$ 0.3500
Adjusted EBITDA	**331.0**	275.3

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2014**	 2013
Operating Unit Contributions to Adjusted Net Income		
NSPI	**$ 66.8**	$ 63.2
Emera Maine	**10.4**	8.9
Emera Caribbean	**6.6**	4.4
Pipelines	**7.2**	7.2
Emera Energy	**61.0**	23.3
Corporate and Other	**(5.4)**	8.4
Adjusted net income attributable to common shareholders	**$ 146.6**	$ 115.4
After-tax derivative mark-to-market gain (loss)	**56.2**	7.4
Net income attributable to common shareholders	**$ 202.8**	$ 122.8

For the millions of Canadian dollars	Three months ended March 31 **2014**	 2013
Operating cash flow before changes in working capital	**$ 265.6**	$ 149.5
Change in investment in working capital	**(119.2)**	(57.5)
Operating cash flow	**146.4**	92.0
Working capital	**$ 661.6**	$ 442.5

Consolidated Income Statement Highlights

Income from Operations

Total operating revenues increased $412.2 million to $1,050.3 million in Q1 2014 compared to $638.1 million in Q1 2013 primarily due to:

- the 2013 acquisitions of the New England Gas Generating Facilities, Brooklyn Energy and Domlec providing $223.9 million in additional revenues
- increased volatility in gas markets providing increased margin opportunity and contribution, and reversal of Q4 2013 mark-to-market losses in Emera Energy in Q1 2014 providing $124.3 million in additional revenues
- the effect of a stronger USD increased CAD operating revenues by $30.2 million and increased electricity pricing in Bayside Power providing $21.4 million in additional revenues

Total operating expenses increased $271.0 million to $733.4 million in Q1 2014 compared to $462.4 million in Q1 2013 primarily due to the 2013 acquisitions of the New England Gas Generating Facilities, Brooklyn Energy and Domlec, which added additional expenses of $205.4 million and higher fuel prices and mark-to-market losses in Bayside Power added additional expenses of $26.8 million.

Income from equity investments

Income from equity investments decreased $9.6 million to $4.2 million in Q1 2014 compared to $13.8 million in Q1 2013 primarily due to a non-recurring gain arising from the settlement of warranty, guarantee and performance obligations related to certain NWP turbines in Q1 2013, partially offset by increased APUC equity earnings in Q1 2014.

Other income (expenses), net

Other income, net decreased $17.4 million to $4.4 million in Q1 2014 compared to $21.8 million in Q1 2013 primarily due to pre-tax gains on the conversion of APUC subscription receipts to common shares in 2013 of $18.1 million.

Income tax expense (recovery)

Income tax expense increased $27.4 million to $66.8 million in Q1 2014 compared to $39.4 million in Q1 2013 primarily due to increased income before provision for income taxes related to mark-to-market gains in Q1 2014.

Operating Cash Flows

Net cash provided by operating activities increased $54.4 million to $146.4 million for the three months ended March 31, 2014 compared to $92.0 million for the three months ended March 31, 2013. The increase was due to higher trading and marketing margin in Emera Energy, higher cash earnings and lower pension contributions in NSPI, partially offset by an increased investment in working capital and increased deferred fuel costs in NSPI.

Developments

Emera

Maritime Link Project

On January 30, 2014, NSPML entered into the first of the Maritime Link Project's major contracts: the supply and installation of the high-voltage direct current ("HVdc") submarine cable. Construction activities started in February in both Nova Scotia and Newfoundland and Labrador, with the beginning of right-of-way clearing activities.

On March 6, 2014, the Government of Canada issued a Federal Loan Guarantee ("FLG") in respect of the Maritime Link Project.

On April 23, 2014, the Maritime Link Financing Trust ("MLFT"), a special purpose funding vehicle formed by Emera, completed its offering of $1.3 billion aggregate principal amount of 3.5 percent amortizing bonds due December 1, 2052 at a price of $999.57 per $1,000 principal amount of bonds for aggregate gross proceeds of approximately $1.3 billion. The bonds are guaranteed by the Government of Canada under the FLG and have been assigned a rating of "AAA" by Standard & Poor's and DBRS Limited. The net proceeds will be used to fund the construction of the Maritime Link Project.

Together with certain financing documentation entered into earlier by or on behalf of MLFT and NSPML, this bond offering fully satisfied the obligations of Emera under the payment obligation agreement previously entered into between Emera, NSPML and the Government of Canada. Upon completion of the bond offering, Emera became obligated under a completion guarantee previously granted by Emera in favour of the Government of Canada (the "Completion Guarantee"). Under the Completion Guarantee, Emera has guaranteed the performance of the obligations of NSPML to cause the completion of the Maritime Link Project in the circumstances and within the timelines provided for in the Completion Guarantee.

Emera Energy

Appeal of MPUC Decision

On March 4, 2014, the Maine Supreme Court ("the Court") ruled on the appeal of the MPUC's 2012 approval of the investment by Emera in its joint venture with First Wind Holdings, LLC and its increased ownership share of Algonquin Power & Utilities Corp.

The Court agreed with Emera's position that Maine's Electric Industry Restructuring Act (the "Act") does not impose a blanket prohibition against all affiliations between transmission and distribution utilities and entities that own generation or generation-related assets in Maine.

However, the Court disagreed with the MPUC's interpretation that section 3204(5) of the Act required a utility to have control over generation or generation-related assets to fall within the prohibition of that section. The Court found that a section 3204(5) prohibition would apply where there exists a sufficient financial interest in the assets of a generator that the interest is likely to produce incentives for favoritism that would undermine the purpose of the Act. Therefore, the Court vacated the approval and sent the matter back to the MPUC for redetermination using the Court's interpretation of section 3204(5) of the Act.

Emera is participating in the MPUC process for redetermination of this matter.

Appointments

Executive

Effective May 1, 2014, Dan Muldoon was appointed Executive Vice President, Major Renewable and Alternative Energy of Emera and will focus on renewable energy initiatives.

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between March 31, 2014 and December 31, 2013 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**78.6**	See consolidated cash flow highlights section.
Receivables, net	**140.0**	Increased primarily due to seasonal trends of business and a change in electricity pricing effective January 1, 2014 in NSPI, and increased commodity pricing and timing of receipts in Emera Energy Services and New England Gas Generating Facilities.
Derivative instruments (current and long-term)	**20.3**	Increased primarily due to favourable USD price positions, partially offset by settlements in NSPI.
Regulatory assets (current and long-term)	**57.4**	Increased primarily due to deferred income taxes, FAM and derivative regulatory assets in NSPI and derivative liability instruments in NSPML, partially offset by amortization in NSPI.
Prepaid expenses	**23.0**	Increased primarily due to timing of provincial grants in lieu of taxes and insurance payments in NSPI and service agreement work and insurance payments in New England Gas Generating Facilities.
Property, plant and equipment, net of accumulated depreciation	**87.7**	Increased primarily due to the favourable effect of a stronger USD on Emera's foreign subsidiaries and capital spending, partially offset by depreciation.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(151.5)**	Decreased primarily due to repayment of debt after a common stock issuance, partially offset by the effect of a stronger USD on Emera's foreign subsidiaries.
Accounts payable	**44.9**	Increased primarily due to increased commodity pricing in Emera Energy and increased business activity in ENL.
Deferred income taxes (current and long-term), net of deferred income tax assets	**68.9**	Increased primarily due to accelerated tax deductions related to property, plant and equipment and decreased non-capital loss carry forwards.
Derivative instruments (current and long-term)	**(41.0)**	Decreased primarily due to reversal of mark-to-market losses in Emera Energy, partially offset by unfavourable price positions relating to interest rate hedges in NSPML.
Regulatory liabilities (current and long-term)	**30.6**	Increased primarily related to derivatives and rate stabilization regulatory liabilities in NSPI resulting from the favourable USD price positions and over-recovery of non-fuel costs respectfully.
Common stock	**260.0**	Increased primarily due to a common share issuance and the dividend reinvestment program.
Accumulated other comprehensive loss	**(69.1)**	Decreased primarily due to the favourable effect of a stronger USD on Emera's foreign subsidiaries.
Retained earnings	**148.5**	Increased due to net income in excess of dividends paid.

OUTSTANDING COMMON STOCK DATA

Issued and outstanding:	millions of shares	Common stock millions of Canadian dollars
December 31, 2012	130.98	$ 1,643.7
Issued for cash under Purchase Plans at market rate	1.85	59.8
Discount on shares purchased under Dividend Reinvestment Plan	-	(2.7)
Options exercised under senior management stock option plan	0.06	1.4
Stock-based compensation	-	0.8
December 31, 2013	132.89	$ 1,703.0
Issuance of common stock	8.66	243.0
Issued for cash under Purchase Plans at market rate	0.54	17.1
Discount on shares purchased under Dividend Reinvestment Plan	-	(0.8)
Options exercised under senior management stock option plan	0.02	0.4
Stock-based compensation	-	0.3
March 31, 2014	**142.11**	**$ 1,963.0**

As at April 22, 2014, the amount of issued and outstanding common shares was 142.2 million.

The weighted average shares of common stock outstanding – basic for the three months ended March 31, 2014 was 142.0 million (2013 – 131.8 million).

NSPI

Overview

NSPI is a fully integrated regulated electric utility with approximately $4.3 billion of assets and the primary electricity supplier in Nova Scotia. NSPI provides electricity generation, transmission and distribution services to approximately 502,000 customers. NSPI's target regulated return on equity ("ROE") range for 2014 is 8.75 percent to 9.25 percent, based on an actual average regulated common equity component of up to 40 percent of actual average regulated capitalization.

Review of 2014

NSPI Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2014**	 2013
Operating revenues – regulated	**$ 417.7**	$ 400.6
Regulated fuel for generation and purchased power (1)	**172.7**	184.3
Regulated fuel adjustment mechanism and fixed cost deferrals	**(0.1)**	(34.8)
Operating, maintenance and general	**69.7**	70.1
Provincial grants and taxes	**9.5**	9.3
Depreciation and amortization	**52.2**	56.0
Total operating expenses	**304.0**	284.9
Income from operations	**113.7**	115.7
Other expenses, net (2)	**1.9**	1.2
Interest expense, net	**28.9**	29.4
Income before provision for income taxes	**82.9**	85.1
Income tax expense (recovery)	**14.1**	19.9
Net income of Nova Scotia Power Inc.	**68.8**	65.2
Preferred stock dividends (3)	**2.0**	2.0
Contribution to consolidated net income	**$ 66.8**	$ 63.2
Contribution to consolidated earnings per common share	**$ 0.47**	$ 0.48
EBITDA	**$ 164.0**	$ 170.5

(1) 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 increased $3.6 million to $66.8 million in Q1 2014 compared to $63.2 million in Q1 2013. Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31
Contribution to consolidated net income – 2013	**$ 63.2**
Decreased electric margin (see Electric Margin section below for explanation)	(5.7)
Decreased depreciation and amortization primarily due to reductions in regulatory amortization (see Regulatory Amortization section below for explanation)	3.8
Decreased income tax expense primarily due to increased tax deductions related to higher pension contributions for 2014	5.8
Other, net (1)	(0.3)
Contribution to consolidated net income – 2014	**$ 66.8**

(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 March 31 **2014**		2013
Electric revenues	**$**	**411.0**	$	393.6
Other revenues		**6.7**		7.0
Operating revenues – regulated	**$**	**417.7**	$	400.6

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. 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, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric revenues consist primarily of export sales, sales to municipal electric utilities and revenues from street lighting.

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

Q1 Electric Sales Volumes
Gigawatt hours ("GWh")

	2014	2013	2012
Residential	**1,568**	1,481	1,403
Commercial	**883**	886	849
Industrial	**601**	638	529
Other	**90**	91	89
Total	**3,142**	3,096	2,870

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

Q1 Electric Revenues
millions of Canadian dollars

		2014		2013		2012
Residential	**$**	**232.8**	$	214.3	$	197.0
Commercial		**109.1**		107.0		99.8
Industrial		**55.8**		59.5		46.6
Other		**13.3**		12.8		11.9
Total	**$**	**411.0**	$	393.6	$	355.3

Electric revenues increased $ 17.4 million to $411.0 million in Q1 2014 from $393.6 million in Q1 2013. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Electric revenues – 2013	**$**	**393.6**
Increased electricity pricing effective January 1, 2014		11.9
Increased residential sales volume, in part due to weather		11.5
Decreased industrial sales volume primarily due to a large industrial customer reducing operations		(5.1)
Other		(0.9)
Electric revenues – 2014	**$**	**411.0**

Regulated Fuel for Generation and Purchased Power

Q1 Production Volumes
GWh

	2014	2013	2012
Coal and petcoke	**2,273**	2,090	1,786
Natural gas	**179**	366	660
Oil	**135**	51	3
Purchased power – other	**47**	169	66
Total non-renewables	**2,634**	2,676	2,515
Wind and hydro – renewables	**416**	373	351
Purchased power – renewables	**254**	248	217
Biomass – renewables	**53**	-	-
Total renewables	**723**	621	568
Total production volumes	**3,357**	3,297	3,083

Q1 Average Fuel Costs

	2014	2013	2012
Dollars per megawatt hour ("MWh")	**$ 51**	$ 56	$ 45

The average unit fuel costs decreased in Q1 2014 compared to Q1 2013 primarily due to decreased coal pricing and favourable generation mix.

NSPI’s regulated fuel for generation and purchased power and certain fuel-related costs (“Fuel Costs”) are affected by generation mix, which is largely dependent on the economic dispatch of the generating fleet, bringing the lowest cost options on stream first, such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance and environmental standards and regulations.

Coal and petroleum coke (“petcoke”) have historically had the lowest per unit fuel cost, after hydro and NSPI-owned 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. NSPI’s use of natural gas has declined in recent years due to price volatility in natural gas markets in Nova Scotia as a result of supply challenges. Renewable production volumes have increased in order for NSPI to meet renewable energy requirements.

Regulated fuel for generation and purchased power decreased $11.6 million to $172.7 million in Q1 2014 compared to $184.3 million in Q1 2013. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Regulated fuel for generation and purchased power – 2013	**$**	**184.3**
Favourable generation mix and plant performance		(7.8)
Decreased commodity prices		(6.0)
Increased hydro and wind production		(3.5)
Unfavourable solid fuel commodity mix		4.5
Increased sales volumes		2.9
Other		(1.7)
Regulated fuel for generation and purchased power – 2014	**$**	**172.7**

Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals

Regulated Fuel Adjustment Mechanism and FAM Regulatory Asset

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

As part of the 2013 General Rate Application settlement agreement, NSPI deferred any Fuel Costs in 2013, which are normally requested to be collected from customers in 2014. As NSPI is proposing no fuel rate increase in 2015, unrecovered Fuel Costs for 2013 and 2014 may be requested to be collected from customers beginning in 2016.

Details of the FAM regulatory asset, classified in “Regulatory assets” on the Consolidated Balance Sheets, are summarized in the following table:

millions of Canadian dollars		**2014**
FAM regulatory asset – Balance as at January 1	**$**	**86.4**
Under (over) recovery of current year's Fuel Costs		12.0
Rebate to (recovery from) customers of prior years’ Fuel Costs		-
Interest on FAM balance		1.8
FAM regulatory asset – Balance as at March 31	**$**	**100.2**

Regulated Fixed Cost Deferrals and Fixed Cost Recovery Deferral Regulatory Assets

NSPI has two regulated fixed cost deferral mechanisms which include a 2013/2014 Rate Stabilization fixed cost recovery deferral (“FCR”) and a 2012 Large Industrial Customers FCR.

<u>2013/2014 Rate Stabilization Fixed Cost Recovery Deferral</u>

On December 21, 2012, the UARB approved an FCR for fiscal 2013 and 2014 as part of the rate stabilization plan. The UARB approved an average net three percent increase in rates effective January 1, 2013 and again on January 1, 2014. To achieve the net three percent increase in rates, a portion of non-fuel costs for 2013 and 2014 may be deferred for future recovery. As part of the rate stabilization plan, any earnings in excess of NSPI’s target regulated ROE range, over the two-year period, reduces the amount deferred. The UARB stipulated the rate stabilization regulatory asset cannot exceed $83.3 million as at December 31, 2014.

Recovery of the 2013/2014 rate stabilization regulatory asset was approved to begin in 2015, when certain other regulatory assets are fully amortized. Amounts recovered in excess of current period non-fuel expenses will be deferred to a regulatory liability.

The rate stabilization regulatory asset or liability includes amounts recognized as a regulated fixed cost deferral and associated interest that is included in “Interest expense, net” on the Consolidated Statements of Income.

Details of the rate stabilization regulatory asset or liability, classified in “Regulatory assets” or "Regulatory liabilities" on the Consolidated Balance Sheets, are summarized in the following table:

millions of Canadian dollars		**2014**
Rate stabilization regulatory asset – Balance as at January 1	**$**	**3.7**
Under (over) recovered current period non-fuel costs		(11.9)
Interest revenue (expense) on rate stabilization FCR balance		(0.1)
Rate stabilization regulatory liability – Balance as at March 31	**$**	**(8.3)**

2012 Large Industrial Customers Fixed Cost Recovery Deferral

The UARB approved a FCR to address uncertainty associated with the operations of two large industrial customers who experienced financial challenges and idled their mills. In 2012, where actual sales to these customers were less than expected when rates were set, the resultant shortfall in contribution toward non-fuel costs was deferred as a regulatory asset for future recovery to be recovered from customers over a three-year period commencing January 1, 2013.

The large industrial customers regulatory asset includes amounts recognized as a regulated fixed cost deferral in 2012, regulatory amortization included in “Depreciation and amortization” in 2013 and 2014 and associated interest included in “Interest expense, net” on the Consolidated Statements of Income.

Details of the large industrial customers regulatory asset, classified in “Regulatory assets” on the Consolidated Balance Sheets are summarized in the following table:

millions of Canadian dollars		**2014**
Large industrial customers regulatory asset – Balance as at January 1	**$**	**33.0**
Recovery of regulatory asset recorded as regulatory amortization		(4.1)
Interest on large industrial customers FCR balance		0.6
Large industrial customers regulatory asset – Balance as at March 31	**$**	**29.5**

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.

For 2013 and 2014, electric margin was affected by the Rate Stabilization FCR, which defers a portion of unrecovered or over-recovered non-fuel costs to achieve the net three percent increase in rates for each year, as approved by the UARB.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI’s customer classes contribute differently to NSPI’s non-fuel electric revenues, with residential and commercial customers contributing more than industrials. Accordingly, changes in residential and commercial load, largely due to the effects of weather and 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 a similar volume change in residential and commercial load.

The addition of new renewable generation facilities to meet greenhouse gas reductions and renewable energy requirements is one of 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 March 31 2014	2013
Fuel electric revenues – current year	**$ 160.4**	$ 147.5
Fuel electric revenues – preceding years	**-**	8.9
Non-fuel electric revenues	**250.6**	237.2
Other revenues	**6.7**	7.0
Operating revenues	**417.7**	400.6

Electric margin is summarized in the following table:

Fuel electric revenues – current year	**160.4**	147.5
Fuel electric revenues – preceding years	**-**	8.9
Total fuel electric revenues	**160.4**	156.4
Regulated fuel for generation and purchased power	**(172.7)**	(184.3)
Regulated fuel adjustment mechanism	**12.0**	27.6
Fuel-related foreign exchange gain (loss) (1)	**0.3**	0.3
Net fuel revenue (expense)	**-**	-
Non-fuel electric revenues	**250.6**	237.2
Regulated fixed cost deferrals	**(11.9)**	7.2
Electric margin	**$ 238.7**	$ 244.4

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

NSPI's electric margin decreased $5.7 million to $238.7 million in Q1 2014 compared to $244.4 million in Q1 2013 primarily due to a decrease in fixed cost deferrals relative to 2013, partially offset by increased non-fuel electric revenues across all customer groups as a result of increased electricity pricing and sales volumes.

Q1 Average Electric Margin (Dollars per MWh)

	2014	2013	2012
Non-fuel electric revenues	**80**	77	68
Regulated fixed cost deferrals	**(4)**	2	3
Electric Margin	**$ 76**	$ 79	$ 71

The change in Q1 average electric margin per MWh in 2014 compared to 2013 is primarily due to effect of fixed cost deferrals, partially offset by increased electricity pricing and changes in customer mix.

Regulatory Amortization

Regulatory amortization is included in "Depreciation and amortization" on the Consolidated Statements of Income.

millions of Canadian dollars	2014
Regulatory amortization – 2013	**$ 9.8**
(Decreased) increased pre-2003 income tax regulatory asset amortization (1)	(4.3)
Other regulatory amortization	(0.2)
Regulatory amortization – 2014	**$ 5.3**

(1) The UARB's 2010 ROE decision has allowed NSPI flexibility in the recognition of additional amortization of the pre-2003 income tax regulatory asset in current periods, which accordingly reduces amortization in future periods resulting in a lower customer rate requirement.

EMERA MAINE

Overview

Emera Maine is a transmission and distribution electric utility with approximately $1.0 billion of assets and serves approximately 155,000 customers in the State of Maine in the United States. Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged, becoming Emera Maine.

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

Review of 2014

Emera Maine Net Income

For the	Three months ended March 31			
millions of USD (except per share amounts)		**2014**		2013
Operating revenues – regulated	**$**	**58.3**	$	53.8
Operating revenues – non-regulated		**0.2**		0.2
Total operating revenues		**58.5**		54.0
Regulated fuel for generation and purchased power		**7.6**		7.7
Transmission pool expense (1)		**6.2**		5.4
Operating, maintenance and general		**13.8**		13.3
Provincial, state and municipal taxes		**2.9**		2.9
Depreciation and amortization		**11.4**		8.7
Total operating expenses		**41.9**		38.0
Income from operations		**16.6**		16.0
Other income (expenses), net		**0.9**		0.7
Interest expense, net		**2.9**		3.0
Income before provision for income taxes		**14.6**		13.7
Income tax expense (recovery)		**5.2**		4.9
Contribution to consolidated net income – USD	**$**	**9.4**	$	8.8
Contribution to consolidated net income – CAD	**$**	**10.4**	$	8.9
Contribution to consolidated earnings per common share – CAD	**$**	**0.07**	$	0.07
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.11**	$	1.01
EBITDA – USD	**$**	**28.9**	$	25.4
EBITDA – CAD	**$**	**31.9**	$	25.8

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

Emera Maine’s USD contribution to consolidated net income increased by $0.6 million to $9.4 million in Q1 2014 compared to $8.8 million in Q1 2013. Highlights of the USD net income changes are summarized in the following table:

For the millions of US dollars		Three months ended March 31
Contribution to consolidated net income – 2013	**$**	**8.8**
Increased operating revenues - regulated (see Operating Revenues - Regulated Section below		4.5
Increased transmission pool expense primarily due to continued transmission investment in New England		(0.8)
Increased depreciation and amortization primarily due to increased regulatory amortization related to stranded costs		(2.7)
Other		(0.4)
Contribution to consolidated net income – 2014	**$**	**9.4**

Emera Maine’s CAD contribution to consolidated net income increased by $1.5 million to $10.4 million in Q1 2014 from $8.9 million in Q1 2013. The impact of a stronger USD, quarter-over-quarter increased CAD earnings by $0.9 million for the three months ended March 31, 2014.

Operating Revenues – Regulated

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

For the	Three months ended March 31			
millions of US dollars		**2014**		2013
Electric revenues	**$**	**42.4**	$	38.2
Transmission pool revenues		**12.2**		11.8
Resale of purchased power		**3.7**		3.8
Operating revenues – regulated	**$**	**58.3**	$	53.8

Electric Revenues

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

Q1 Electric Sales Volumes

GWh	**2014**	2013	2012
Residential	**239**	221	212
Commercial	**225**	220	217
Industrial	**92**	82	86
Other	**3**	3	3
Total	**559**	526	518

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

Q1 Electric Revenues
millions of US dollars

		2014		2013		2012
Residential	**$**	**20.8**	$	19.2	$	18.0
Commercial		**15.8**		14.7		14.3
Industrial		**3.4**		2.6		2.4
Other		**2.4**		1.7		2.6
Total	**$**	**42.4**	$	38.2	$	37.3

Electric revenues increased $4.2 million to $42.4 million in Q1 2014 compared to $38.2 million in Q1 2013. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended March 31
Electric revenues – 2013	**$**	**38.2**
Increased primarily due to transmission and stranded cost rate changes		1.8
Increased sales volume primarily due to weather		2.4
Electric revenues – 2014	**$**	**42.4**

Q1 Average Electric Revenue / MWh

		2014		2013		2012
Dollars per MWh	**$**	**76**	$	73	$	72

The change in average electric revenue per MWh in Q1 2014 compared to Q1 2013 reflects transmission and stranded cost rate changes.

Transmission Pool Revenues and Expenses

These 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 March 31
		2014		2013
Transmission pool revenues	**$**	**12.2**	$	11.8
Transmission pool expenses		**6.2**		5.4
Net transmission pool revenues	**$**	**6.0**	$	6.4

Emera Maine’s net transmission pool revenues decreased $0.4 million to $6.0 million in Q1 2014 compared to $6.4 million in Q1 2013 primarily due to increased regional network system charges associated with an increased level of regionally funded transmission assets.

EMERA CARIBBEAN

Overview

Emera Caribbean includes the following investments:

Consolidated Investments

- 80.5 percent investment in Light & Power Holdings Ltd. ("LPH") and its wholly owned subsidiary Barbados Light & Power Company Ltd. ("BLPC"), a vertically integrated cost-of-service utility and the provider of electricity on the island of Barbados. BLPC serves approximately 126,000 customers and is regulated by the Fair Trading Commission, Barbados. BLPC's approved regulated return on rate base for 2014 is 10.0 percent. A fuel pass-through mechanism ensures fuel costs are recovered.

- 50.0 percent direct and 30.4 percent indirect interest in Grand Bahama Power Company Ltd. ("GBPC"), a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves approximately 19,000 customers. GBPC's approved regulated return on rate base for 2014 is 10.0 percent. A fuel pass-through mechanism ensures fuel costs are recovered.

- 41.8 percent indirect controlling interest, through LPH, in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica. Domlec serves approximately 35,000 customers and is regulated by the Independent Regulatory Commission, Dominica.

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

Non-Consolidated Investment

- 15.4 percent indirect interest, through LPH, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the Caribbean island of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2014

Emera Caribbean Net Income

For the millions of USD (except per share amounts)	Three months ended March 31 2014	2013
Operating revenues – regulated	**$ 100.7**	$ 96.4
Operating revenues – non-regulated	**1.9**	2.3
Total operating revenues	**102.6**	98.7
Regulated fuel for generation and purchased power	**57.5**	58.5
Non-regulated direct costs	**1.7**	2.0
Operating, maintenance and general	**24.8**	23.0
Property taxes (1)	**0.3**	0.4
Depreciation and amortization	**8.9**	7.5
Total operating expenses	**93.2**	91.4
Income from operations	**9.4**	7.3
Income from equity investment	**0.5**	0.2
Other income (expenses), net	**2.0**	0.8
Interest expense, net	**2.9**	2.7
Income before provision for income taxes	**9.0**	5.6
Income tax expense (recovery)	**0.3**	0.5
Net income	**8.7**	5.1
Non-controlling interest in subsidiaries	**(1.5)**	(0.8)
Preferred stock dividends (2)	**1.3**	-
Contribution to consolidated net income – USD	**$ 5.9**	$ 4.3
Contribution to consolidated net income – CAD	**$ 6.6**	$ 4.4
Contribution to consolidated earnings per common share – CAD	**$ 0.05**	$ 0.03
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.12**	$ 1.02
EBITDA – USD	**20.8**	15.8
EBITDA – CAD	**22.9**	16.0

(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 $1.6 million to $5.9 million in Q1 2014 compared to $4.3 million in Q1 2013. Highlights of the net income changes are summarized in the following table:

For the millions of US dollars	Three months ended March 31
Contribution to consolidated net income – 2013	**$ 4.3**
Increased electric margin primarily due to increased sales volumes in GBPC, partially offset by decreased sales volumes in LPH	0.5
Decreased OM&G expenses primarily due to operational cost savings in GBPC	1.4
Increased other income, net primarily due to recognition of regulatory asset relating to the Earnings Share Mechanism in GBPC and the recognition of investment income relating to LPH's self-insurance fund	1.2
Increased preferred share dividends due to GBPC's preferred share issuance in January 2013	(1.3)
Net earnings effect of the acquisition of controlling interest in Domlec as of April 10, 2013	0.2
Other	(0.4)
Contribution to consolidated net income – 2014	**$ 5.9**

Emera Caribbean's CAD contribution to consolidated net income increased by $2.2 million to $6.6 million in Q1 2014 compared to $4.4 million in Q1 2013. The impact of a stronger USD, quarter-over-quarter increased CAD earnings by $0.6 million for the three months ended March 31, 2014.

Operating Revenues – Regulated

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

For the millions of US dollars	Three months ended March 31 **2014***	2013
Electric revenues – base rates	**$ 42.8**	$ 37.5
Fuel charge	**57.0**	58.1
Total electric revenues	**99.8**	95.6
Other revenues	**0.9**	0.8
Operating revenues – regulated	**$ 100.7**	$ 96.4

*Domlec contributed $8.2 million to operating revenues - regulated.

Electric Revenues

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

Q1 Electric Sales Volumes

GWh

	2014*	2013	2012
Residential	**104**	95	94
Commercial	**177**	171	173
Industrial	**24**	21	22
Other	**7**	6	6
Total	**312**	293	295

*Domlec contributed 10 GWh to residential, 11 GWh to commercial, nil to industrial, and 1 GWh to other

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

Q1 Electric Revenues

millions of US dollars

	2014*	2013	2012
Residential	**$ 31.2**	$ 29.0	$ 29.6
Commercial	**58.5**	57.4	59.7
Industrial	**8.4**	7.5	7.8
Other	**1.7**	1.7	3.7
Total	**$ 99.8**	$ 95.6	$ 100.8

*Domlec contributed $3.5 million to residential, $4.5 to commercial, nil to industrial, and $0.2 million to other

Electric revenues increased $4.2 million to $99.8 million in Q1 2014 compared to $95.6 million in Q1 2013. Highlights of the changes are summarized in the following table:

For the millions of US dollars	Three months ended March 31
Electric revenues – 2013	**$ 95.6**
Increased due to the acquisition of controlling interest in Domlec	8.2
Decreased fuel charge primarily due to lower fuel prices	(4.0)
Electric revenues – 2014	**$ 99.8**

Q1 Average Electric Revenue/MWh

	2014	2013	2012
Dollars per MWh	**$ 320**	$ 326	$ 342

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 the base rates, whereas the fuel charge and fuel costs do not have a material effect on electric margin or net income. In BLPC, GBPC and Domlec, customer classes contribute differently to the Company's base rate revenue, with residential and commercial customers contributing more than industrials. Residential and commercial load is primarily affected by changes in weather and economic conditions, while industrial load is primarily affected by changes in the economic conditions.

Electric margin is summarized in the following table:

For the millions of US dollars	Three months ended March 31 **2014**	 2013
Operating revenues – regulated	**$ 100.7**	$ 96.4
Less: Other revenues	**(0.9)**	(0.8)
Total electric revenues	**99.8**	95.6
Total electric revenues are broken down as follows:		
Electric revenues – base rate	**42.8**	37.5
Fuel charge	**57.0**	58.1
Total electric revenues	**99.8**	95.6
Regulated fuel for generation and purchased power	**57.5**	58.5
Regulatory amortization (1)	**0.7**	0.7
Electric margin (2)	**$ 41.6**	$ 36.4

(1) Included in "Depreciation and amortization" on the Consolidated Statements of Income.
(2) The acquisition of Domlec in Q2 2013 contributed $4.7 million in Q1 2014 to Emera Caribbean electric margin.

Emera Caribbean's electric margin increased $5.2 million to $41.6 million in Q1 2014 compared to $36.4 million in Q1 2013 primarily due to the acquisition of controlling interest of Domlec in Q2 2013.

Q1 Average Electric Margin /MWh

	2014	2013	2012
Dollars per MWh	**$ 133**	$ 124	$ 115

Regulated Fuel for Generation and Purchased Power

Q1 Production Volumes
GWh

	2014*	2013	2012
Oil	**338**	314	322

* Domlec contributed 24 GWh

Q1 Average Fuel Costs/MWh

	2014	2013	2012
Dollars per MWh	**$ 170**	$ 186	$ 202

Regulated fuel for generation and purchased power decreased $1.0 million to $57.5 million in Q1 2014 compared to $58.5 million in Q1 2013 primarily due to lower fuel prices, partially offset by the acquisition of controlling interest of Domlec.

Other Income (Expenses), Net

As a component of its regulatory agreement with the GBPA, GBPC has an Earnings Share Mechanism to allow for earnings above or below its approved 10 percent return on rate base to be deferred to a regulatory asset or liability at the rate of 50 percent of amounts below a 9 percent return on rate base and 50 percent of amounts above 11 percent return on rate base respectively. GBPC will amortize this deferral into income beginning in 2016.

Other income (expenses), net, increased $1.2 million to $2.0 million in Q1 2014 compared to $0.8 million in Q1 2013 due to the recognition of a regulatory asset in GBPC of $0.5 million related to the Earnings Share Mechanism for Q1 2014 and the recognition of $0.4 million in investment income relating to LPH's self-insurance fund asset.

PIPELINES

Overview

Pipelines comprises Emera's wholly owned Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") and the Company's 12.9 percent interest in the M&NP.

- Brunswick Pipeline is a 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. Brunswick Pipeline is accounted for as a direct financing lease.

- The investment in M&NP is accounted for on the equity basis.

Review of 2014

Pipelines' Net Income

For the	Three months ended March 31			
millions of Canadian dollars (except per share amounts)		**2014**		2013
Operating revenues – regulated	**$**	**11.4**	$	12.7
Accretion (1)		**0.1**		0.1
Income from equity investment		**3.7**		3.7
Other income (expenses), net		**0.1**		(0.1)
Interest expense, net		**6.2**		7.5
Income before provision for income taxes		**8.9**		**8.7**
Income tax expense (recovery)		**1.7**		1.5
Contribution to consolidated net income	**$**	**7.2**	$	7.2
Contribution to consolidated earnings per common share	**$**	**0.05**	$	0.05
EBITDA	**$**	**15.2**	$	16.3

(1) Accretion is included in "Depreciation and amortization" on the Consolidated Statements of Income.

Pipelines' contribution to consolidated net income did not change overall in Q1 2014 compared to Q1 2013.

EMERA ENERGY

Overview

Emera Energy includes the following:

- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business.
- Emera Energy Generation ("EEG"), a wholly owned portfolio of electricity generation facilities in New England and Maritime Canada with 1,370 MW of total capacity.
- Emera's 50.0 percent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northern Massachusetts.
- Emera's 49.0 percent investment in NWP, a 420 MW portfolio of wind energy projects in the northeastern United States.

Wholly owned investments are consolidated. The investments in Bear Swamp and NWP are accounted for on the equity basis.

Emera Energy Services

EES purchases and sells physical natural gas and electricity and provides related energy asset management services. EES is also responsible for commercial management of electricity production and fuel procurement for Emera Energy Generation's fleet. Established in 2002, EES currently has approximately 75 employees engaged in commercial activities and related back office, legal and other support functions. EES's primary market is northeastern North America, but it is also active in the Marcellus shale gas region, the US Gulf Coast and Central Canada. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and its business relies on knowledge of the region's energy markets, understanding of pipeline infrastructure, a network of counterparty relationships and a focus on customer service.

EES's financial results are largely dependent on market conditions. EES manages the commodity risk associated with its business by limiting open positions, and by utilizing derivative instruments (primarily swaps, options, futures and forwards) to hedge price risk.

Emera Energy Generation

EEG owns and operates a portfolio of recent vintage, high efficiency, non-utility electricity generating facilities in northeast North America, as outlined in the table below:

Facility	Location	Capacity (MW)	Fuel	Description
New England				
Bridgeport	Connecticut	520	Natural gas	Merchant – Selling to ISO-New England ("ISO-NE")
Tiverton	Rhode Island	265	Natural gas	Merchant – Selling to ISO-NE
Rumford	Maine	265	Natural gas	Merchant – Selling to ISO-NE
Total New England		**1,050**		
Maritime Canada				
Bayside	New Brunswick	290	Natural gas	Long-term power purchase agreement ("PPA") November - March; Merchant selling to Maritimes and ISO NE for remainder of year
Brooklyn	Nova Scotia	30	Biomass	Long term PPA for full output
Total Maritime Canada		**320**		
Total EEG		**1,370**		

The New England facilities were acquired in November 2013; Brooklyn Power was acquired in July 2013; and Bayside Power was acquired in 2009. In total, EEG has approximately 115 employees.

For that portion of its output not committed under PPAs, EEG sells into price-based competitive markets, and earns revenues through the physical delivery of power and ancillary services, such as load regulation. From time to time, EEG will enter into short-term physical or financial contracts to hedge the electricity and fuel price risk inherent in selling to the spot market. Over time, as the New England facilities are fully integrated, EEG expects to reduce the price risk associated with selling into a daily market by contracting a portion of plant output via bilateral contracts and/or implementing longer term hedge strategies. The New England facilities also participate in the regional capacity market, whereby they are compensated for being available to provide power.

Held-For-Trading Derivatives

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.

Review of 2014

Emera Energy Adjusted Contribution to Consolidated Net Income

For the	Three months ended March 31			
millions of Canadian dollars (except per share amounts)		**2014**		2013
Trading and marketing margin (1)	**$**	**82.3**	$	20.0
Electricity sales (2)		**261.3**		25.3
Total operating revenues – non-regulated		**343.6**		45.3
Non-regulated fuel for generation and purchased power (3)		**214.5**		13.9
Operating, maintenance and general		**28.7**		8.7
Depreciation and amortization		**11.2**		1.6
Total operating expenses		**254.4**		24.2
Adjusted income (loss) from operations		**89.2**		21.1
Income from equity investments (4)		**0.5**		14.1
Other income (expenses), net		**0.6**		0.3
Interest expense, net		**1.5**		0.1
Adjusted income (loss) before provision for income taxes		**88.8**		35.4
Income tax expense (recovery) (5)		**27.8**		12.1
Adjusted contribution to consolidated net income (loss)	**$**	**61.0**	$	23.3
After-tax derivative mark-to-market gain (loss)	**$**	**56.2**	$	7.4
Contribution to consolidated net income	**$**	**117.2**	$	30.7
Adjusted contribution to consolidated earnings per common share – basic	**$**	**0.43**	$	0.18
Contribution to consolidated earnings per common share – basic	**$**	**0.83**	$	0.23
Adjusted EBITDA	**$**	**101.5**	$	37.1

(1) Trading and marketing margin excludes a pre-tax mark-to-market gain of $92.3 million for the quarter ended March 31, 2014 (2013 - $14.1 million gain)
(2) Electricity sales exclude a pre-tax mark-to-market gain of $0.1 million for the quarter ended March 31, 2014 (2013 -$0.1 million loss)
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $6.7 million for the quarter ended March 31, 2014 (2013 - $1.0 million gain)
(4) Income from equity investments excludes a pre-tax mark-to-market loss of $4.8 million for the quarter ended March 31, 2014 (2013 - $4.7 million loss)
(5) Income tax expense excludes $24.7 million relating to mark-to-market gains for the quarter ended March 31, 2014 (2013 - $2.9 million expense)

Emera Energy's contribution to consolidated net income decreased $86.5 million to $117.2 million in Q1 2014 compared to $30.7 million in Q1 2013. Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars		Three months ended March 31
Contribution to consolidated net income – 2013	**$**	**30.7**
Increased trading and marketing margin primarily due to very strong market conditions in northeastern United States and Ontario		62.3
Increased electricity sales primarily due to the acquisition of the New England Gas Generating Facilities and higher electricity prices		236.0
Increased non-regulated fuel for purchased power primarily due to the acquisition of the New England Gas Generating Facilities and higher commodity prices		(200.6)
Increased OM&G due to the acquisition of the New England Gas Generating Facilities and increased performance based compensation accruals resulting from the increase in trading and marketing margin		(20.0)
Increased depreciation and amortization primarily due to the acquisition of the New England Gas Generating Facilities		(9.6)
Decreased income from equity investments primarily due to a non-recurring gain in Q1 2013 from the settlement of warranty obligations related to certain NWP turbines		(13.6)
Increased interest expense primarily due to the acquisition of the New England Gas Generating Facilities		(1.4)
Increased income tax expense due to increased income before provision for income taxes		(15.7)
Increased mark-to-market gains, net of tax primarily due to changes in trading and marketing gas and power contract positions		48.8
Other		0.3
Contribution to consolidated net income – 2014	**$**	**117.2**

A portion of earnings are exposed to foreign exchange fluctuations, thereby affecting the CAD contribution to net earnings. The impact of a stronger USD quarter-over-quarter increased CAD earnings by $9.2 million in Q1 2014 compared to Q1 2013.

Emera Energy Services

Adjusted EBITDA

Adjusted EBITDA for EES is summarized in the following table:

For the		Three months ended March 31		
		2014		2013
Trading and marketing margin	**$**	**82.3**	$	20.0
OM&G		**13.1**		4.9
Other income (expenses), net		**1.0**		0.2
Adjusted EBITDA	**$**	**70.2**	$	**15.3**

Trading and Marketing Margin

Trading and marketing margin is composed of EES's corresponding purchases and sales of natural gas and electricity, pipeline capacity expenses and energy asset management services' revenues.

Trading and marketing margin increased $62.3 million to $82.3 million in Q1 2014 compared to $20.0 million in Q1 2013. Q1 2014 saw sustained and unprecedented pricing and volatility in several of EES's markets, largely the result of cold weather. The increase in trading and marketing margin reflects growth in the volume of business and EES's success in utilizing its extensive market knowledge and access to transportation capacity within these market conditions.

OM&G

The increase in OM&G primarily reflects an increase in performance based compensation accruals resulting from the increase in margin quarter-over-quarter.

Emera Energy Generation

Operating Statistics

For the	Three months ended March 31					
	2014	2013	**2014**	2013	**2014**	2013
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
New England	**1,307**	-	**91.7 %**	- %	**57.6 %**	- %
Maritime Canada	**549**	476	**99.2 %**	**99.4** %	**81.3 %**	**75.9** %
Total	**1,856**	476	**93.4 %**	**99.4** %	**63.1 %**	**75.9** %

(1) Sales volumes represent the actual electricity output of the plants.
(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.
(3) Net capacity factor represents the plant's actual output for the period as a percentage of its nameplate capacity.

Sales volumes increased in Q1 2014 primarily due the acquisition of the New England Gas Generating Facilities.

Net capacity factor is a measure of time in the period the plant produced power for sale in the marketplace. It is generally a function of plant availability and plant economics vis-a-vis the market. In Q1 2014, the Maritime Canada facilities operate exclusively under Power Purchase Agreements (“PPA”), and accordingly are dispatched by the PPA holders. The increase in capacity factor in the Maritime facilities quarter-over-quarter is primarily due to gas supply shortfalls in 2013 under Bayside’s firm supply agreement.

The New England facilities sell into price based competitive markets. The primary reason the capacity factor is lower for the New England facilities as compared to the Maritime plants is that the Rumford facility operates with a capacity factor of approximately 20 percent, reflecting current electricity and gas supply price dynamics.

Adjusted EBITDA for Emera Energy Generation

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

For the	Three months ended March 31					
	2014	2013	**2014**	2013	**2014**	2013
	New England		Maritime Canada		Total	
Electricity sales	**$ 210.8**	$ -	$ **50.5**	$ 25.3	**$ 261.3**	$ 25.3
Non-regulated fuel for generation and purchased power	**180.0**	-	**39.7**	15.2	**219.7**	15.2
Non-regulated electric margin	**30.8**	**-**	**10.8**	10.1	**41.6**	10.1
OM&G	**7.3**	-	**7.6**	3.8	**14.9**	3.8
Other income (expenses), net	**-**		**(0.3)**	0.1	**(0.3)**	0.1
Adjusted EBITDA	**$ 23.5**	**-**	$ **2.9**	$ 6.4	**$ 26.4**	$ 6.4

Adjusted EBITDA increased $20.0 million to $26.4 million in Q1 2014 from $6.4 million in Q1 2013 primarily due to the acquisition of the New England Gas Generating Facilities.

CORPORATE AND OTHER

Overview

Corporate and Other includes the following consolidated and non-consolidated investments:

Consolidated Investments

- ENL, a wholly owned subsidiary, focused on transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls in Labrador. ENL's subsidiary, NSP Maritime Link Inc. is developing the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre subsea cables, between the island of Newfoundland and Nova Scotia.

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

Non-consolidated investments

- Emera's 24.2 percent investment in APUC, a growth oriented public corporation, traded on the Toronto Stock Exchange ("TSX") under the symbol "AQN", in the independent power and rate regulated utilities business sectors. APUC has a diversified portfolio of renewable power and utility businesses primarily through two operating subsidiaries. One subsidiary owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets. A second subsidiary owns and operates a diversified rate regulated portfolio of North American electric, natural gas and water distribution utility systems. The investment in APUC is accounted for on the equity basis.

- Emera's 34.9 percent investment in LIL, held by ENL ,a $2.6 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of the Muskrat Falls energy between Labrador and the island of Newfoundland. The investment in LIL is accounted for on the equity basis.

- Emera's 37.4 percent investment in Atlantic Hydrogen Inc. ("AHI"), accounted for on the equity basis.

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

Corporate also includes interest revenue on intercompany financings recorded in "Revenue", and costs associated with corporate activities that are not directly allocated to the operations of Emera's consolidated subsidiaries and investments. Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, corporate business development and corporate governance, internal audit, investor relations, risk management, insurance and certain human resource activities.

Review of 2014

Corporate and Other

For the millions of Canadian dollars	Three months ended March 31 **2014**	 2013
Revenue (1)	**$ 6.2**	$ 10.5
Non-regulated operating revenue	**8.0**	11.6
Non-regulated direct costs	**8.2**	12.8
Operating, maintenance and general	**10.9**	10.7
Depreciation and amortization	**0.6**	0.2
Total operating expenses	**19.7**	23.7
Income (loss) from operations	**(5.5)**	(1.6)
Income (loss) from equity earnings	**4.2**	0.3
Other income (expenses), net	**2.4**	21.3
Interest expense	**8.6**	9.8
Income (loss) before provision for income taxes	**(7.5)**	10.2
Income tax expense (recovery)	**(7.7)**	(2.4)
Preferred stock dividends	**5.6**	4.2
Contribution to consolidated net income	**$ (5.4)**	$ 8.4
Contribution to consolidated earnings per common share – basic	**$ (0.04)**	$ 0.06
EBITDA	**$ 1.7**	$ 20.2

(1) Revenue consists of interest from Brunswick Pipeline and NWP; and preferred dividends from Brunswick Pipeline.

Corporate and Other's contribution to consolidated net income decreased $13.8 million to $(5.4) million in Q1 2014 compared to $8.4 million in Q1 2013. Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31
Contribution to consolidated net income – 2013	**$ 8.4**
Revenue decreased primarily due to timing of intercompany dividends	(4.3)
Income from equity investments increased primarily due to increased APUC earnings and increased APUC ownership percentage, AHI equity losses recorded in Q1 2013, and equity earnings in LIL being recorded in 2014 (1)	3.9
Other income, net, decreased primarily due to the gains on converting APUC subscription receipts in 2013	(18.9)
Income tax recovery increased primarily due to decreased income before provision for income taxes	5.3
Other	0.2
Contribution to consolidated net income – 2014	**$ (5.4)**

(1) In Q4 2013, the Company recorded an impairment charge to write down its investment in AHI as AHI's path to commercialization was less certain. Therefore, the Company recorded equity earnings of nil relating to AHI in Q1 2014.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through its regulated utilities and equity investments. The utilities' 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 are generally capable of paying dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the three months ended March 31, 2014 and 2013 include:

Three months ended March 31 millions of Canadian dollars		2014		2013	$ Change 2014 versus 2013
Cash and cash equivalents, beginning of period	**$**	**100.8**	$	86.7	14.1
Provided by (used in):					
Operating cash flow before changes in working capital		**265.6**		149.5	116.1
Change in investment in working capital		**(119.2)**		(57.5)	(61.7)
Operating activities		**146.4**		92.0	54.4
Investing activities		**(82.9)**		(176.6)	93.7
Financing activities		**11.6**		106.2	(94.6)
Effect of exchange rate changes on cash and cash equivalents		**3.5**		3.6	(0.1)
Cash and cash equivalents, end of period	**$**	**179.4**	$	111.9	67.5

Operating Cash Flows

Net cash provided by operating activities increased $54.4 million to $146.4 million for the three months ended March 31, 2014 compared to $92.0 million for the three months ended March 31, 2013. The increase was due to higher trading and marketing margin in Emera Energy, higher cash earnings and lower pension contributions in NSPI, partially offset by an increased investment in working capital and increased deferred fuel costs in NSPI.

Investing Cash Flows

Net cash used in investing activities decreased $93.7 million to $82.9 million for the three months ended March 31, 2014 compared to $176.6 million for the three months ended March 31, 2013. The decrease was primarily due to the increased investment in APUC and initial investment in LIL in Q1 2013, partially offset by increased capital expenditures.

Capital expenditures for the three months ended March 31, 2014, including allowance for funds used during construction (“AFUDC”), were approximately $86 million compared to $72 million in 2013 primarily due to increased capital spending in NSPML. Details of the capital spend are shown below:

- $45 million in NSPI (2013 – $46 million);
- $11 million in Emera Maine (2013 – $14 million);
- $6 million in Emera Caribbean (2013 – $5 million);
- $24 million in Corporate and Other, including NSPML (2013 – $7 million).

The above amounts have been restated to reflect the new segment structure as of Q1 2014.

Financing Cash Flows

Net cash provided by financing activities decreased $94.6 million to $11.6 million for the three months ended March 31, 2014 compared to $106.2 million for the three months ended March 31, 2013. The decrease was primarily due to the issuance of common stock partially offset by proceeds use to pay off short-term debt in Q1 2014 as compared to a net increase in debt in Q1 2013.

Contractual Obligations

As at March 31, 2014, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2014	2015	2016	2017	2018	Thereafter	Total
Long-term debt	$ 325.0	$ 89.7	$ 265.6	$ 37.4	$ 443.9	$ 2,363.1	$ 3,524.7
Purchased power (1)	99.0	156.5	162.9	168.8	151.2	1,824.4	2,562.8
Coal, biomass, oil and natural gas supply	198.8	153.1	71.8	13.6	10.2	-	447.5
Pension and post-retirement obligations (2)	36.9	12.1	11.5	10.8	10.3	561.8	643.4
Asset retirement obligations	0.7	1.0	2.3	2.2	1.0	333.8	341.0
Interest payment obligations (3)	137.7	166.9	160.0	151.5	146.1	2,197.3	2,959.5
Transportation (4)	88.4	55.3	24.2	21.2	9.8	9.1	208.0
Long-term service agreements (5)	47.1	47.6	37.6	29.2	25.0	186.5	373.0
Capital projects	146.1	111.5	47.2	121.7	-	-	426.5
Leases (6)	3.1	3.8	3.2	2.8	2.7	13.5	29.1
Other	3.0	3.5	1.3	1.3	1.3	39.8	50.2
	$ 1,085.8	$ 801.0	$ 787.6	$ 560.5	$ 801.5	$ 7,529.3	$ 11,565.7

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

(2) The estimated minimum required Company contributions are determined based on accrued obligations (and exclude current service cost for future service) and are based on actuarial funding valuations. In determining the contractual obligations for the last 9 months of 2014, and from 2015 to 2018 related to the pension plan, the figures take into consideration pre-paid contributions made by the Company in 2012 and the terms of the most recent collective agreement. The total amount shown related to the pension plan for years after 2018 is equal to the plan's wind-up shortfall at December 31, 2013 (assuming service accruals stop and salary for pension calculation purposes is frozen), less the Company's contractual obligations for 2014 to 2018, all adjusted for interest. As the pension plan is not actually being wound-up, this information is presented for illustration only. Actuarial valuations are performed annually and as such, future Company contractual obligations will be updated annually

(3) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at March 31, 2014

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

(5) Long-term service agreements: outsourced management of computer and communication infrastructure, vegetation management, maintenance of certain generating equipment, and services related to a generation facility and wind operating agreements.

(6) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

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 bank line referred to above, which results in an equal amount of credit being considered drawn and unavailable.

As at March 31, 2014, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera – Operating and acquisition credit facility	June 2018 – Revolver	$ 700	$ 138	$ 562
NSPI – Operating credit facility (1)	June 2018– Revolver	500	301	199
Emera Maine – in USD – Operating credit facility	September 2014 – Revolver	80	48	32
Other – in USD – Operating credit facilities	2014	21	-	21

(1) Extended to June 2018 on January 10, 2014, with no change in commercial terms from the prior agreement.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at March 31, 2014.

As at March 31, 2014, approximately 80 percent 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 and preferred shares are expected to be $280 million in 2014, $355 million in 2015 and $250 million in 2016.

Emera's future liquidity and capital needs 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.

OUTLOOK

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, regulatory deferrals and the approved recovery of regulatory deferrals, and the timing and amount of capital expenditures.

NSPI anticipates earning a regulated ROE within its targeted range in 2014 and expects its rate base and earnings to be similar to 2013. NSPI continues to focus on cost control, productivity and service improvements as well as making regulated investments in renewable energy and system reliability projects.

On April 1, 2014, NSPI announced it does not plan to file a general rate application related to electricity rates for 2015, and it also proposed no fuel rate increase for 2015, which will be subject to UARB approval.

On April 7, 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove the efficiency charge 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 Efficiency Nova Scotia when it is cheaper than generation on a go-forward basis. The Program Costs are capped for 2015 at $35.0 million and the UARB will provide regulatory oversight of the Program Costs thereafter. The Program costs for 2015 will be deferred as a regulatory asset and recoverable from customers over an eight year period beginning in 2016. The UARB will determine how the Program costs will be recovered from customers for 2016 and beyond.

On April 11, 2014, NSPI announced an annual community investment of up to $3.4 million, increasing annually by 2 percent, renewable for up to 10 years, to fund energy savings upgrades for low income customers with electrically heated homes. The community investment will not be recoverable in rates from customers.

Capital expenditures for 2014, including AFUDC are forecasted to be $283.0 million (2013 - $207.7 million actual). The Company expects to finance its capital expenditures with funds from operations and debt.

Emera Maine

Emera Maine's earnings are most directly impacted by the combined impacts of the range or rates of return on equity and equity thickness approved by its regulators, the prudent management and approved recovery of operating costs, load, and the timing and amount of capital expenditures.

In 2014, Emera Maine expects to invest approximately $72.9 million (2013 - $84.2 million actual), including approximately $23.2 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 equity thickness approved by their regulators, the prudent management and approved recovery of operating costs, and the timing and amount of capital expenditures. Earnings are also affected by the investment returns of Emera's interest in the BLPC self-insurance fund.

The Barbados government has passed legislation, which, when ultimately proclaimed and operational, will impact the electricity market as it relates to the addition of renewable generation. BLPC is working with the government and stakeholders to implement this legislation and to extend its franchise.

Emera Caribbean plans to invest approximately $55.2 million in total capital programs in 2014 (2013 - $24.1 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.

The changing natural gas markets in the northeastern United States and Atlantic Canada may provide opportunities for investment. Emera will evaluate opportunities for growth in this area as they present themselves.

Emera Energy

Emera Energy's trading and marketing business is generally dependent on market conditions. In particular, market volatility, 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, resulting from the combined impacts of cold weather and constraints in the supply of natural gas, which contributed to very strong earnings from trading and marketing. If market volatility decreases in the future, trading and marketing earnings may be lower. 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, including the Marcellus Shale region.

Emera Energy’s 2014 results will include a full year of operations from its New England Gas Generating Facilities, which were acquired in Q4 2013. Earnings from Emera Energy generating assets are largely dependent on market conditions and in particular, the relevant pricing of electricity and natural gas. Efficient operations of the fleet to ensure unit availability, cost management and effective commercial performance are key success factors. Current market conditions are such that the addition of the New England Gas Generating Facilities to Emera Energy’s portfolio is expected to increase earnings modestly in the medium term, increasing over time as debt is paid down.

Corporate and Other

Corporate and Other is comprised of intercompany financing revenues, timing of capital expenditures on the Maritime Link Project, the timing of equity investments into the Labrador-Island Link, project based construction services activity by Emera Utility Services, fluctuations in APUC earnings, corporate interest expense and other corporate activities, offset by corporate administration costs not allocated to operating subsidiaries. Corporate’s contribution to consolidated net income is expected to be lower in 2014 as business growth leads to increased financing, corporate administration costs and business development costs.

ENL

Through its subsidiary, NSP Maritime Link Inc., ENL has invested approximately $88.0 million (December 31, 2013 - $65.2 million), including AFUDC, in the estimated $1.56 billion development of the Maritime Link Project. It is continuing to finalize project contracts and has commenced right-of-way clearing activities this quarter. AFUDC on invested equity is being capitalized at the rate of 9.0 percent.

An equity investment, by ENL, of approximately $80.0 million is expected during fiscal 2014 in order to finance the equity component of the expected construction spending in the year. 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.

The Labrador-Island Transmission Project is currently estimated at $2.6 billion. ENL is a partner with Nalcor Energy in this project and invested $67.7 million in the Labrador-Island Transmission Link Project in Q1 2013. Equity earnings, effectively equivalent to AFUDC, are being recorded at the rate of 8.8 percent as the rate approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities. ENL has an ongoing equity investment opportunity in the Labrador-Island Transmission Link Project. Future earnings are dependent upon the timing of additional equity investment. ENL does not expect to make additional investments in this project in 2014.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy and construction related 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 March 31	
			2014	2013
	Nature of Service	**Presentation**		
Sales:				
Emera Energy	Net sale of natural gas	Operating revenue - non-regulated	**$ -**	$ 3.9
Emera Energy	Sale of power	Operating revenue - non-regulated	**3.6**	1.3
Emera Utility Services	Maintenance and construction services	Operating revenue - non-regulated	**2.3**	3.7
EUS Bahamas	Construction, operations management and engineering services	Operating revenue - non-regulated	**2.2**	2.4
Purchases:				
NSPI	Net purchase of natural gas	Regulated fuel for generation and purchased power	**-**	3.9
NSPI	Purchase of power	Regulated fuel for generation and purchased power	**3.6**	1.3
NSPI	Maintenance services	OM&G	**0.5**	0.8
NSPI	Construction services	Property, plant and equipment	**1.8**	2.9
GBPC	Maintenance services	OM&G	**2.1**	1.8
GBPC	Construction services	Property, plant and equipment	**0.1**	0.6

Following are transactions between Emera and its equity investments:

M&NP

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $8.4 million (2013 – $9.5 million) for the three months ended March 31, 2014. The amount is recognized in “Regulated fuel for generation and purchased power” or netted against energy marketing margin in “Non-regulated operating revenues” and is measured at the exchange amount. As at March 31, 2014, the amount payable to the related party was $2.8 million (December 31, 2013 – $2.5 million) and is under normal interest and credit terms.

Emera has a loan receivable from M&NP bearing interest at 1 percent per annum maturing on November 30, 2019. As at March 31, 2014, the loan balance was $2.5 million and is recognized as “Due from related parties” on Emera’s Consolidated Balance Sheets (December 31, 2013 – $2.5 million).

NWP

Emera Maine has a 20-year contract with NWP that commenced in July 2011 for 20 percent of the capacity and energy generated from a 60 MW wind facility in Maine, as directed by the MPUC. In the ordinary course of business, Emera Maine paid NWP $0.7 million for the three months ended March 31, 2014 (2013 – $0.5 million) for the capacity and energy, which is measured at the exchange amount. Losses (or gains) from the difference between the cost of the acquired capacity and energy and the associated resale revenues are recoverable by Emera Maine in its stranded cost rates.

In 2013 Emera, through a wholly owned subsidiary, had a $150 million USD loan receivable from a wholly owned subsidiary of NWP, in which Emera holds a 49 percent interest. This loan was subsequently repaid in November 2013. In the ordinary course of business, Emera earned $3.0 million for the three months ended March 31, 2013 which was recognized in “Interest expense, net” and was measured at the exchange amount.

In the ordinary course of business, Emera Energy Services, a wholly owned subsidiary of Emera, provided NWP with energy management services for $0.1 million (2013 – $0.1 million) recognized in "Operating revenues, non-regulated" for the three months ended March 31, 2014 and is measured at the exchange amount.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Emera's risk management profile and practices have not changed materially from December 31, 2013.

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**March 31 2014**		December 31 2013
Derivative instrument assets (current and other assets)	**$**	**15.9**	$	15.4
Derivative instrument liabilities (current and long-term liabilities)		**(14.8)**		(7.2)
Net derivative instrument assets (liabilities)	**$**	**1.1**	$	8.2

Hedging Impact Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended March 31 **2014**		 2013
Operating revenues – regulated	**$**	**(1.0)**	$	0.7
Non-regulated fuel for generation and purchased power		**5.3**		1.4
Income from equity investments		**(0.1)**		(0.1)
Effective net gains (losses)	**$**	**4.2**	$	2.0

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

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

For the millions of Canadian dollars		Three months ended March 31 **2014**		 2013
Non-regulated fuel for generation and purchased power	**$**	**(1.9)**	$	1.4
Ineffective gains (losses)	**$**	**(1.9)**	$	1.4

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**March 31 2014**		December 31 2013
Derivative instrument assets (current and other assets)	**$**	**70.8**	$	51.4
Regulatory assets (current and other assets)		**36.1**		8.6
Derivative instrument liabilities (current and long-term liabilities)		**(35.5)**		(8.6)
Regulatory liabilities (current and long-term liabilities)		**(70.8)**		(51.4)
Net asset (liability)	**$**	**0.6**	$	-

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended March 31 **2014**		 2013
Regulated fuel for generation and purchased power	**$**	**14.3**	$	(2.2)
Net gains (losses)	**$**	**14.3**	$	(2.2)

Held-for-trading Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**March 31 2014**		December 31 2013
Derivative instruments assets (current and other assets)	**$**	**44.5**	$	44.1
Derivative instruments liabilities (current and long-term liabilities)		**(95.7)**		(171.2)
Net derivative instrument assets (liabilities)	**$**	**(51.2)**	$	(127.1)

Held-for-trading Items Recognized in Net Income

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

For the millions of Canadian dollars		Three months ended March 31 **2014**		 2013
Operating revenues – non-regulated	**$**	**194.3**	$	52.0
Other income (expenses), net		**(4.6)**		-
Net gains (losses)	**$**	**189.7**	$	52.0

Business Risks

There were no material changes in the Company's significant business risks during Q1 2014 from those disclosed in the MD&A for the year ended December 31, 2013.

DISCLOSURE AND INTERNAL CONTROLS

The Company, under the supervision and participation of management, including the Chief Executive Officer and Chief Financial Officer, has designed as at March 31, 2014 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, 2014 and ending on March 31, 2014, 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 other post-retirement employee 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

In Q1 2014, Emera adopted Accounting Standards Update (“ASU”) Number (“No.”) 2013-11. This ASU amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, similar tax loss, or tax credit carryforward exists. The purpose of the amendment was to reduce diversity in practice by providing guidance on the presentation of unrecognized tax benefits and to better reflect the manner in which an entity would settle at the reporting date, any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses or tax carryforwards exist. The Company was in compliance with this standard and therefore, the adoption of this standard had no impact on the financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q1 2014**	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012
Operating revenues	**$ 1,050.3**	$ 594.4	$ 491.2	$ 506.5	$ 638.1	$ 512.9	$ 476.4	$ 501.3
Net income attributable to common shareholders	**202.8**	21.0	28.8	44.9	122.8	42.7	44.7	53.2
Earnings per common share – basic	**1.43**	0.16	0.22	0.34	0.93	0.34	0.36	0.43
Earnings per common share – diluted	**1.40**	0.16	0.22	0.34	0.92	0.34	0.36	0.43
Adjusted earnings per common share – basic	**1.03**	0.47	0.29	0.32	0.88	0.46	0.35	0.37

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 unseasonal 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.