No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This prospectus is a base shelf prospectus. This short form base shelf prospectus has been filed under legislation in the province of Nova Scotia that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.

Information has been incorporated by reference in this short form base shelf prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Emera Incorporated at 5151 Terminal Road, Halifax, Nova Scotia B3J 1A1 (telephone: 902-428-6096) and are also available electronically at www.sedar.com.*

A registration statement relating to these securities has been filed with the United States Securities and Exchange Commission. These securities may not be sold nor may offers to buy be accepted prior to the time the registration statement becomes effective. This prospectus shall not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of these securities in any state in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such state.

No distribution of securities pursuant to this prospectus will be made to purchasers in Canada.

Short Form Base Shelf Prospectus

New Issue June 8, 2016

Emera

EMERA INCORPORATED

U.S.$1,250,000,000
Unsecured, Subordinated Notes
First Preferred Shares Issuable Upon Automatic Conversion

Emera Incorporated ("Emera" or the "Company") may offer and sell from time to time up to U.S.$1,250,000,000 principal amount of unsecured, subordinated notes (the "Notes"), in one or more transactions during the 25 month period ending July 8, 2018 that this base shelf prospectus (this "Prospectus"), including any amendments hereto, remains valid. The Notes are convertible into First Preferred Shares of Emera in certain circumstances (see "Description of the Notes—Automatic Conversion" and "Description of Conversion Preferred Shares"). The Notes offered hereunder may be offered separately or together, in separate series, in amounts, at prices, with maturities, and on terms to be set forth in one or more shelf prospectus supplements (each, a "Prospectus Supplement"). A Prospectus Supplement may include other specific terms pertaining to the Notes that are not prohibited by the parameters set forth in this Prospectus. See "Description of the Notes".

All shelf information permitted under applicable laws to be omitted from this Prospectus will be contained in one or more Prospectus Supplements that will be delivered to purchasers together with this Prospectus. Each Prospectus Supplement will be incorporated by reference into this Prospectus for the purposes of securities legislation as of the date of the Prospectus Supplement and only for the purposes of the Notes to which the Prospectus Supplement pertains.

Emera may sell the Notes to or through underwriters purchasing as principal and may also sell the Notes to one or more other purchasers directly or through agents. Any underwriting syndicate in respect of an offering of Notes will be led by J.P. Morgan Securities LLC. See "Plan of Distribution." The Prospectus Supplement relating to a particular offering of Notes will identify each underwriter or agent, as the case may be, engaged by Emera in connection with the offering and sale of the Notes and will set forth the terms of the offering of such Notes, including the method of distribution of such Notes, the proceeds to Emera and any fees, discounts or other compensation payable to underwriters or agents, and any other material terms of the offering of such Notes.

In connection with any offering of Notes, the underwriters or agents may over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution."

Investing in the Notes involves risk. See "Risk Factors."

Emera is permitted, under the multi-jurisdictional disclosure system adopted by the United States ("U.S."), to prepare this Prospectus in accordance with Canadian disclosure requirements. You should be aware that such requirements are different from those of the U.S.

Financial statements incorporated herein have been prepared in accordance with U.S. generally accepted accounting principles, which is referred to as "U.S. GAAP."

Owning the Notes may subject you to tax consequences both in the United States and Canada. This Prospectus or any applicable Prospectus Supplement may not describe these tax consequences fully. You should read the tax discussion in any applicable Prospectus Supplement.

Your ability to enforce civil liabilities under U.S. federal securities laws may be affected adversely by the fact that Emera is organized under the laws of Nova Scotia, that some or all of the officers and directors of Emera may be residents of Canada, that some or all of the experts named herein may be residents of Canada and that all or a substantial portion of our assets and the assets of said persons are located outside of the U.S.

J. Wayne Leonard and Richard P. Sergel are directors of Emera who reside outside of Canada and each of these directors has appointed Emera Incorporated as agent for service of process at 5151 Terminal Road, Halifax, Nova Scotia B3J 1A1. Purchasers are advised that it may not be possible for investors to enforce judgements obtained in Canada against any person who resides outside of Canada, even if the party has appointed an agent for service of process.

The Notes have not been approved or disapproved by the United States Securities and Exchange Commission (the "SEC") or any state securities commission nor has the SEC or any state securities commission passed upon the accuracy or adequacy of this Prospectus. Any representation to the contrary is a criminal offense.

Emera's head office is located at 5151 Terminal Road, Halifax, Nova Scotia B3J 1A1.

Post-Acquisition Map of Combined Emera and TECO Energy Operations

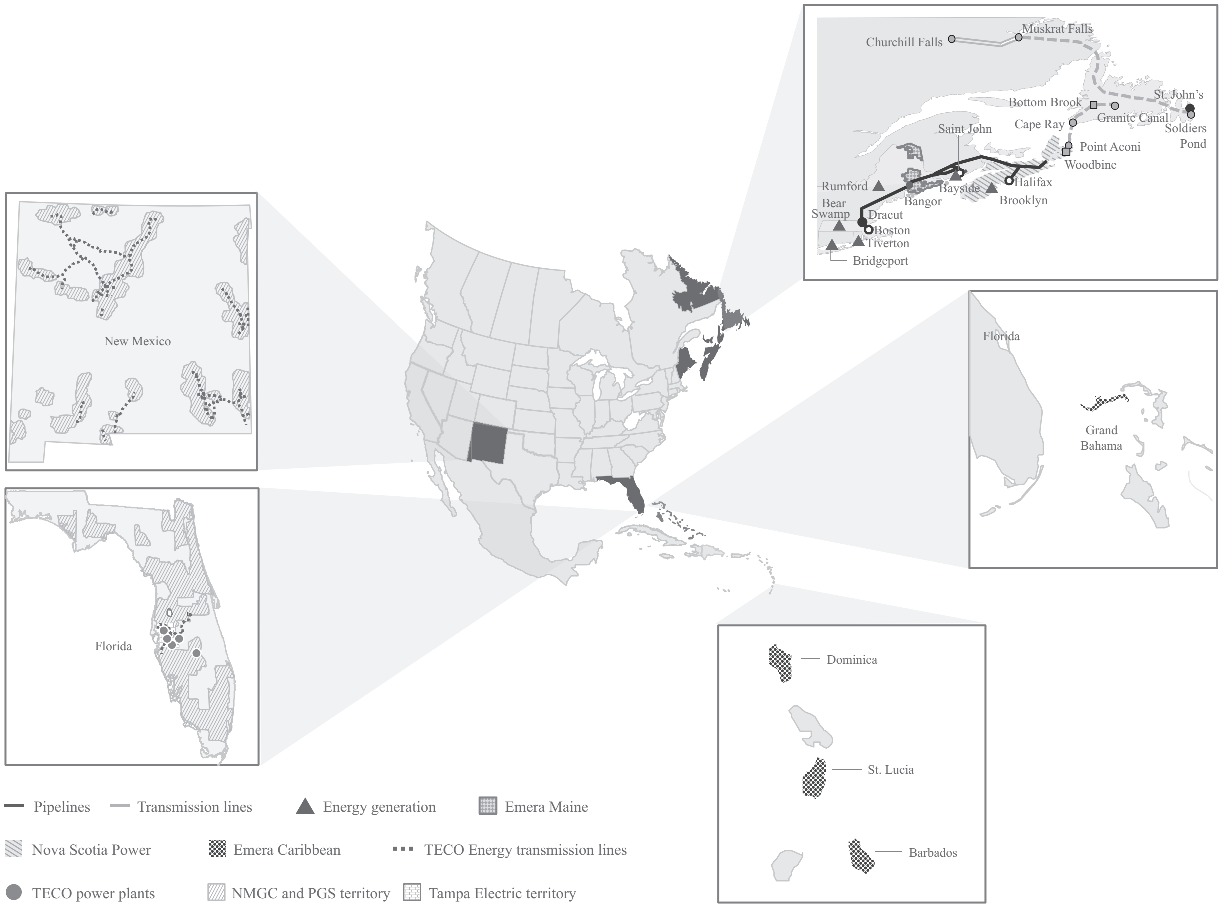


TABLE OF CONTENTS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Please refer to the "Glossary" beginning on page 40 of this Prospectus for a list of defined terms used herein.

This Prospectus, including the documents incorporated herein by reference, contains forward-looking information within the meaning of applicable securities laws which reflects current expectations of Emera's management regarding: (i) the future growth, results of operations, performance, business prospects and opportunities of the Company; (ii) the timing and completion of the Acquisition Capital Markets Transactions (as defined herein) and the Acquisition (as defined herein); (iii) the benefits and the impact of the Acquisition, any offering hereunder, the other Acquisition Capital Markets Transactions and the Acquisition Credit Facilities (and the proposed refinancing thereof) on the financial position of the Company; and (iv) the future performance, business prospects and opportunities of TECO Energy and the integration of its electric and gas utility businesses with the existing operations of Emera. These expectations may not be appropriate for other purposes. Such statements are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. The words "anticipates," "believes," "budget," "could," "estimates," "expects," "forecasts," "intends," "may," "might," "plans," "projects," "schedule," "should," "targets," "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 reflects management's current beliefs and is based on information currently available to the Company's management.

The forward-looking information in this Prospectus, including the documents incorporated herein by reference, includes, but is not limited to, statements regarding: Emera's consolidated net income and cash flow; the growth and diversification of Emera's business and earnings base; future annual net income and dividend growth; expansion of Emera's business in the United States and elsewhere; the completion of the Acquisition; the completion of the Acquisition Capital Markets Transactions; the expected compliance by Emera and its subsidiaries with the regulation of their operations; the expected timing of regulatory decisions; forecasted gross capital expenditures; the nature, timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; expectations related to annual operating cash flows; the expectation that Emera will continue to have reasonable access to capital in the near to medium terms; expected debt maturities and repayments; expectations about increases in interest expense and/or fees associated with debt securities and credit facilities; no material adverse credit rating actions being expected in the near term; the number of customers served in the future; the successful execution of relationships with third-parties, such as agreements relating to the Maritime Link Project, Muskrat Falls and the Assembly of Nova Scotia Mi'Kmaq Chiefs; the impact of currency fluctuations; expected changes in electricity rates; and the impacts of planned investment by the industry of gas transportation infrastructure within Northeastern United States.

The forward-looking information contained herein pertaining to the Acquisition and the financing thereof, the future performance, business prospects and opportunities of TECO Energy and the integration of its electric and gas utility businesses with the existing operations of Emera includes, but is not limited to, statements regarding: the expectation that the Acquisition will increase the Company's consolidated rate base and total customers; the expectation that the Acquisition will be accretive to earnings per common share, assuming a stable currency environment; the impact of the Acquisition on the Company's total assets, net income, long-term growth, access to equity and debt capital markets, credit profile, economies of scale and ability to deploy capital; expectations regarding the nature, timing and costs of capital spending of Emera, TECO Energy, New Mexico Gas Company ("NMGC"), Tampa Electric and Peoples Gas System ("PGS"); the expected future unemployment rates, housing starts and GDP growth rates in Florida and New Mexico; the expectations regarding rate base growth; the complementary management teams and corporate cultures of Emera and TECO Energy; the projected use of TECO Energy's tax carry-forwards; the locations of the combined operations after completion of the Acquisition; the projected coal and petroleum coke consumption for Tampa Electric; the expectations with respect to the impact of costs and compliance as a result of new and existing laws, regulations and guidelines, including, but not limited, to environmental and climate change matters; the financial liability with respect to Superfund sites and former manufactured gas plant sites of Tampa Electric and PGS, as well as other potential contamination liabilities; the impact of legal proceedings; the financing of the Acquisition, including, but not limited to, the use of the net proceeds of any offering hereunder and the other Acquisition Capital Markets Transactions, the repayments under the Acquisition Credit Facilities and the terms and conditions of the Acquisition Credit Agreements; the impact of any offering hereunder, the other Acquisition Capital Markets Transactions, the Acquisition Credit Facilities, the timing and closing of the Acquisition, capital lease and finance obligations on the capital structure of the Company; the material attributes and characteristics of the Notes and any other securities issued in connection with the Acquisition Capital Markets Transactions; the plan of distribution; and the risk factors relating to the Acquisition, the post-Acquisition combined business and operations of the Company and TECO Energy and the Acquisition Capital Markets Transactions.

The forward-looking information 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 include, but are not limited to: derivative financial instruments, including, but not limited to, hedging availability; commodity price and availability risk; foreign exchange risk; interest rate risk; commercial relationship risk; credit risk; rating agency risk; labour risk; weather risk; regulatory risk; environmental risk; capital market risk, including, but not limited to, economic conditions, cost of financing, capital resources and liquidity risk; construction and development risks; inability to complete an offering hereunder and the financing and the completion of the Acquisition; an increase in the cash purchase price of the Acquisition; uncertainty regarding the length of time required to complete the Acquisition; the anticipated benefits of the Acquisition not materializing or not occurring within the time periods anticipated by the Company; the impact of significant demands placed on the Company as a result of the Acquisition; failure by the Company to repay the Acquisition Credit Facilities; potential unavailability of the Acquisition Credit Facilities; alternate sources of funding, including the Acquisition Capital Markets Transactions, that would be used to replace the Acquisition Credit Facilities not being available when needed; lack of control by the Company of TECO Energy and its subsidiaries prior to the closing of the Acquisition; the impact of the Acquisition-Related Expenses; accuracy and completeness of TECO Energy's publicly disclosed information; increased indebtedness of Emera after the closing of the Acquisition; that an offering hereunder could result in a downgrade of the Company's credit ratings; historical and pro forma combined financial information not being representative of future performance; potential undisclosed liabilities of TECO Energy; ability to retain key personnel of TECO Energy following the Acquisition; operating and maintenance risks; risks relating to the financing of Emera; risks associated with changes in economic conditions; that developments in technology could reduce demand for electricity and gas; integration of NMGC and its impact on TECO Energy's business and operations; changes in customer energy-usage patterns; risk of failure of information technology infrastructure and cybersecurity; disruption of fuel supply; natural disasters or other catastrophic events; impairment testing of certain long-lived assets could result in impairment charges; indebtedness of TECO Energy; risks relating to the Notes; unanticipated maintenance and other expenditures; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks associated with pension plan performance and funding requirements; regulatory and government decisions including, but not limited to, changes to environmental, financial reporting and tax legislation and regulations; risk of loss of licences and permits; risk of loss of service area; market energy sales prices; maintenance of adequate insurance coverage; impact of Acquisition-Related Expenses; labor relations and management resources. For additional information with respect to the Company's risk factors and risk factors relating to the post-Acquisition business of Emera, the operations of Emera and TECO Energy, the Acquisition and the Acquisition Capital Markets Transactions, reference should be made to the section of this Prospectus entitled "Risk Factors" and to the documents incorporated herein by reference and to the Company's continuous disclosure materials filed from time to time with the CSA.

All forward-looking information in this Prospectus and in the documents incorporated herein by reference is qualified in its entirety by the above cautionary statements and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

WHERE TO FIND MORE INFORMATION

Emera has filed with the SEC, under the Securities Act, a registration statement on Form F-10 relating to the Notes and First Preferred Shares qualified by this Prospectus. This Prospectus, which constitutes a part of the registration statement, does not contain all of the information contained in the registration statement, certain items of which are contained in the exhibits to the registration statement as permitted by the rules and regulations of the SEC. Statements included or incorporated by reference in this Prospectus about the contents of any contract, agreement or other documents referred to are not necessarily complete, and in each instance, you should refer to the exhibits for a complete description of the matter involved. Emera files annual and quarterly financial information and material change reports, business acquisition reports and other material with the Nova Scotia Securities Commission and the securities regulatory authorities in each of the other Canadian provinces.

Under the multi-jurisdictional disclosure system adopted by the U.S., documents and other information that Emera files with the SEC may be prepared in accordance with the disclosure requirements of Canada, which are different from those of the U.S. You may read and download any public document that Emera has filed with the Nova Scotia Securities Commission and the securities regulatory authorities in each of the other Canadian provinces on SEDAR at www.sedar.com. You may read and copy any document that we have filed with the SEC at the SEC's public reference room in Washington D.C., and may also obtain copies of those documents from the public reference room of the SEC at 100 F Street, N.E., Washington, D.C. 20549 by paying a fee. Additionally, you may read and download some of the documents that we have filed on EDGAR at www.sec.gov.

DOCUMENTS FILED AS PART OF THE REGISTRATION STATEMENT

The following documents are being filed with the SEC as part of the Registration Statement: (i) the documents referred to under the heading "Documents Incorporated by Reference"; (ii) the consent of PricewaterhouseCoopers LLP; (iii) the consent of Ernst & Young LLP; (iv) the consent of Osler, Hoskin & Harcourt LLP; (v) the consent of Davis Polk & Wardwell LLP; (vi) the powers of attorney from Emera's directors and officers; (vii) the form of Indenture between Emera, American Stock Transfer & Trust Company, LLC and CST Trust Company; and (viii) the Statement of Eligibility under the Trust Indenture Act of 1939, of American Stock Transfer & Trust Company, LLC.

DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Company listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this Prospectus:

(i) the Annual Information Form of Emera dated March 30, 2016 for the year ended December 31, 2015;

(ii) the audited consolidated financial statements of Emera as at and for the years ended December 31, 2015 and December 31, 2014, together with the auditors' report thereon;

(iii) Management's Discussion and Analysis of Emera for the year ended December 31, 2015;

(iv) the unaudited condensed consolidated interim financial statements of Emera as at and for the three months ended March 31, 2016 and March 31, 2015;

(v) Management's Discussion and Analysis of Emera for the three months ended March 31, 2016; and

(vi) the Management Information Circular of Emera distributed in connection with Emera's annual meeting of shareholders held on May 17, 2016 (as refiled on March 24, 2016).

In addition, the disclosure documents of TECO Energy listed below and filed by it with the SEC, and each also filed by the Company on SEDAR as "Documents incorporated by reference not previously filed" on June 1, 2016, are specifically incorporated by reference into and form an integral part of this Prospectus:

(i) the audited consolidated financial statements and schedule of TECO Energy as at and for the years ended December 31, 2015, 2014 and 2013 contained in TECO Energy's Annual Report on Form 10-K filed with the SEC for the year ended December 31, 2015;

(ii) Management's Report on Internal Control over Financial Reporting of TECO Energy contained in TECO Energy's Annual Report on Form 10-K filed with the SEC for the year ended December 31, 2015; and

(iii) the unaudited consolidated condensed financial statements of TECO Energy as at and for the three months ended March 31, 2016 and 2015 contained in TECO Energy's Quarterly Report on Form 10-Q filed with the SEC for the quarter ended March 31, 2016.

Any documents of the type referred to above (other than confidential material change reports), and any other documents required under applicable securities laws to be incorporated by reference into this Prospectus, if filed by Emera with the provincial securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the termination of any offering of Notes, shall be deemed to be incorporated by reference into this Prospectus. To the extent that any document or information incorporated by reference into this Prospectus is included in a report that is filed with or furnished to the SEC, such document or information shall be deemed to be incorporated by reference as an exhibit to the Registration Statement. In addition, any other report filed with or furnished to the SEC by the Company shall be deemed to be incorporated by reference as an exhibit to the Registration Statement, if and to the extent that such report expressly so provides.

Upon a new annual information form, new management information circular, new annual consolidated financial statements and accompanying management's discussions and analysis being filed by Emera with (and where required, accepted by) the applicable securities regulatory authorities during the currency of this Prospectus, the previous annual information form, the previous management information circular, the previous annual consolidated financial statements and accompanying management's discussion and analysis, all consolidated interim financial statements and accompanying management's discussion and analysis, and all material change reports filed prior to the commencement of the financial year of Emera in which the new annual information form is filed shall be deemed no longer to be incorporated into this Prospectus for the purposes of future offers and sales of Notes hereunder. Upon any interim financial statements and accompanying management's discussion and analysis being filed by Emera with (and, where required, accepted by) the applicable securities regulatory authorities during the currency of this Prospectus, all interim financial statements and accompanying management's discussion and analysis filed prior to the new interim financial statements shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder.

Any statement contained in a document incorporated or deemed to be incorporated by reference in this Prospectus shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed to be an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of Emera's documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Emera at 5151 Terminal Road, Halifax, Nova Scotia B3J 1A1 (telephone 902-428-6096). These documents are also available through the internet on the Company's website at www.emera.com or on SEDAR which can be accessed at www.sedar.com. Copies of TECO Energy's documents incorporated herein by reference may be obtained on request without charge from the Director of Investor Relations of TECO Energy at 702 North Franklin Street, Tampa, Florida 33602 (telephone 813-228-4111). These documents are also available through the internet on TECO Energy's website at www.tecoenergy.com or on the SEC's website which can be accessed at www.sec.gov. The information contained on, or accessible through, any of these websites is not incorporated by reference into this Prospectus and is not, and should not be considered to be, a part of this Prospectus, unless it is explicitly so incorporated.

PRESENTATION OF FINANCIAL INFORMATION

All financial information of Emera (with the exception of the Emera Maine and Emera Caribbean sections of "Management's Discussion and Analysis") included in this Prospectus as at December 31, 2015, 2014 and 2013 is reported in Canadian dollars and has been derived from audited historical financial statements of Emera that were prepared in accordance with U.S. GAAP. All financial information of Emera (with the exception of the Emera Maine and Emera Caribbean sections of "Management's Discussion and Analysis") included in this Prospectus as at March 31, 2016 and 2015 is reported in Canadian dollars and has been derived from unaudited historical financial statements of Emera that were prepared in accordance with U.S. GAAP. All financial information of TECO Energy included in this Prospectus as at December 31, 2015, 2014 and 2013 is reported in U.S. dollars and has been derived from audited historical financial statements of TECO Energy that were prepared in accordance with U.S. GAAP. All financial information of TECO Energy included in this Prospectus as at March 31, 2016 and 2015 is reported in U.S. dollars and has been derived from unaudited historical financial statements of TECO Energy that were prepared in accordance with U.S. GAAP. The revenues and expenses of TECO Energy shown in the unaudited pro forma consolidated statements of earnings of the Company for the three month period ended March 31, 2016 and for the year ended December 31, 2015 are reported in Canadian dollars and reflect the average U.S. dollar-to-Canadian dollar exchange rates for such periods. The assets and liabilities of TECO Energy shown in the unaudited pro forma consolidated balance sheet of the Company as of March 31, 2016 are reported in Canadian dollars and reflect the U.S. dollar-to-Canadian dollar period-end closing exchange rate. Financial information in this Prospectus that has been derived from the unaudited pro forma consolidated financial statements has been translated to Canadian dollars on the same basis. Certain tables in this Prospectus may not sum to total due to rounding.

Non-U.S. GAAP Financial Measures

Emera uses financial measures that do not have standardized meaning under U.S. GAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-U.S. GAAP measures by adjusting certain U.S. GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period, as detailed below:

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

Emera believes that these non-U.S. GAAP measures are useful to investors because they are frequently used by securities analysts, investors and other interested parties in the evaluation of companies and will provide investors with a useful tool for assessing the comparability between periods of its ability to generate cash from operations sufficient to pay taxes, to service debt and to undertake capital expenditures.

You are encouraged to evaluate each adjustment to the corresponding U.S. GAAP measure and the reasons management considers them appropriate for supplemental analysis. In evaluating these non-U.S. GAAP measures, you should be aware that in the future Emera may incur expenses similar to the adjustments in this Prospectus. This presentation should not be construed as an inference that Emera's future results will be unaffected by such items.

The SEC has adopted rules to regulate the use in filings with the SEC and public disclosures and press releases of non-U.S. GAAP financial measures. The rules prohibit the following, among other things, in filings with the SEC:

- exclusion of charges or liabilities that require, or will require, cash settlement or would have required cash settlement, absent an ability to settle in another manner, from non-U.S. GAAP liquidity measures; and
- adjustment of a non-U.S. GAAP performance measure to eliminate or smooth items identified as non-recurring, infrequent or unusual, when the nature of the charge or gain is such that it has occurred in the past two years or is reasonably likely to recur within the next two years.

The non-U.S. GAAP financial information presented in this Prospectus may not comply with these rules.

The non-U.S. GAAP financial information presented in this Prospectus are measures of our performance that are not required by, or presented in accordance with, U.S. GAAP and should not be considered as an alternative to cash flows from operations, net income, net operating income or any other performance measure derived in accordance with U.S. GAAP or as an alternative measure of our liquidity.

For additional information regarding non-U.S. GAAP measures See "Management's Discussion and Analysis."

Adjusted Contribution to Consolidated Net Income, Adjusted Income Before Provision for Income Taxes and Adjusted Contribution to Consolidated Earnings per Common Share—Basic

Emera calculates these non-U.S. GAAP measures by excluding the effect of certain mark-to-market adjustments from their respective U.S. GAAP equivalents.

Mark-to-market adjustments are further discussed in the sections under "Management's Discussion and Analysis": "—Consolidated Financial Highlights," "—Emera Energy—Review of 2015," "—Pipelines—Review of 2015," "—Corporate and Other—Review of 2015," "—Emera Energy—Review of 2016," "—Pipelines—Review of 2016 and Corporate and Other—Review of 2016."

Adjusted Net Income and Adjusted Earnings per Common Share—Basic

Emera calculates comparable measures by excluding the effect of:

- the mark-to-market adjustments related to Emera's held-for-trading derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company, LLC ("Bear Swamp") and Northwest Wind Partners II, LLC ("NWP"), until NWP's sale on January 29, 2015;
- the amortization of transportation capacity recognized as a result of certain trading and marketing transactions;
- the mark-to-market adjustments related to an interest rate swap in Emera Brunswick Pipeline Company Limited ("EBPC"); and
- the mark-to-market adjustments included in Emera's other income related to the effect of USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering in connection with the Acquisition.

Management believes excluding from income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows.

Mark-to-market adjustments are further discussed in the sections under "Management's Discussion and Analysis": "—Consolidated Financial Highlights," "—Emera Energy—Review of 2015," "—Pipelines—Review of 2015," "—Corporate and Other—Review of 2015," "—Emera Energy—Review of 2016," "—Pipelines—Review of 2016" and "Corporate and Other—Review of 2016."

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

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Net income attributable to common shareholders	$ 44.3	$160.1	$397.2	$406.7	$217.5
After-tax mark-to-market gain (loss)	(75.9)	(11.5)	67.2	87.5	(41.9)
Adjusted net income attributable to common shareholders	120.2	171.6	330.0	319.2	259.4
Earnings per common share – basic	0.30	1.10	2.72	2.84	1.64
Adjusted earnings per common share – basic	0.81	1.18	2.26	2.23	1.96

Emera EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-U.S. GAAP financial measure used in this Prospectus in respect of Emera. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality.

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

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies, but in Emera's management's view appropriately reflects Emera's specific financial condition. These measures are not intended to replace "Net income" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. Emera's EBITDA and Adjusted EBITDA are discussed further in the section entitled "Management's Discussion and Analysis".

The following is a reconciliation of reported net income to EBITDA and Adjusted EBITDA:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
Net income	$ 54.8	$174.1	$ 452.4	$ 452.8	$255.3
Interest expense, net	75.2	44.4	212.6	179.8	172.2
Income tax expense (recovery)	26.8	61.4	92.4	113.6	43.3
Depreciation and amortization	87.5	82.8	339.9	329.0	297.8
EBITDA	244.3	362.7	1,097.3	1,075.2	768.6
Mark-to-market gain (loss), excluding income tax and interest	(75.1)	(21.5)	66.1	128.7	(60.9)
Adjusted EBITDA	$319.4	$384.2	$1,031.2	$ 946.5	$829.5

TECO Energy EBITDA

EBITDA is a non-U.S. GAAP financial measure used in this Prospectus in respect of TECO Energy. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality.

TECO Energy's EBITDA may not be comparable to the EBITDA measures of other companies, but in TECO Energy's management's view appropriately reflects TECO Energy's specific financial condition. These measures are not intended to replace "Net income" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. TECO Energy's EBITDA is discussed further in the section entitled "Management's Discussion and Analysis."

The following is a reconciliation of reported net income from continuing operations to EBITDA:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars				
Net income from continuing operations	$ 73.7	$ 63.8	$241.2	$206.4	$188.7
Interest expense, net	45.9	47.9	186.4	171.1	161.4
Income tax expense	35.7	39.9	155.3	138.9	112.6
Depreciation and amortization	89.8	85.5	349.0	315.3	291.8
EBITDA	$245.1	$237.1	$931.9	$831.7	$754.5

Electric Margin

"Electric margin" is a non-U.S. GAAP financial measure used to show the amounts that Nova Scotia Power Incorporated ("NSPI"), Barbados Light & Power Company Limited ("BLPC"), Grand Bahama Power Company Ltd. ("GBPC") and Dominica Electricity Services Ltd. ("Domlec") retain to recover non-fuel costs. Prudently incurred fuel costs are recovered from customers, except in Domlec, where substantially all fuel costs are passed to customers through the fuel pass-through mechanism. Management believes measuring electric margin shows the portion of the utilities' revenues that directly contribute to Emera's income as distinguished from the portion of revenues that are managed through fuel adjustment mechanisms, which have a minimal impact on income. Emera Energy also reports "Electric margin" because the sales price of electricity and the cost of natural gas used to generate it are highly correlated. However, their absolute values can vary materially over time. Emera Energy believes that "Electric margin," as the net result, provides a meaningful measure of the business' performance in addition to the absolute values of sales and fuel expenses, which are also reported. Electric margin, as calculated by Emera, may not be comparable to the electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. This measure is not intended to replace "Income from operations" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. Electric margin is discussed further in the sections under "Management's Discussion and Analysis" "—NSPI—Electric Margin," "—the Emera Caribbean—Electric Margin" and "—Emera Energy—Adjusted EBITDA".

CAUTION REGARDING UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

This Prospectus contains the unaudited pro forma consolidated balance sheet as at March 31, 2016 and consolidated statements of earnings of the Company for the three month period ended March 31, 2016 and for the year ended December 31, 2015, giving effect to: (i) the Acquisition Capital Markets Transactions (as discussed under "Summary—Financing the Acquisition"), (ii) the issuance of common shares of Emera ("Common Shares") upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures, as discussed under "Description of Other Indebtedness—Convertible Debentures") and (iii) the consummation of the Acquisition. Any offering of Notes hereunder is not contingent upon the consummation of the Acquisition, the other Acquisition Capital Markets Transactions or payment in full of the Final Instalment of the Convertible Debentures. The unaudited pro forma financial statements included herein do not give effect to the sale by Emera of 50.1 million common shares of Algonquin Power & Utilities Corp. ("APUC"). See "Summary—Recent Developments."

Emera intends to raise up to approximately Cdn$6.6 billion in aggregate principal amount in the Acquisition Capital Markets Transactions. The aggregate principal amounts raised in the Acquisition Capital Markets Transactions and the terms on which such securities are issued are dependent on market and other conditions and may vary. To the extent (i) Emera raises less than Cdn$6.6 billion in connection with the Acquisition Capital Markets Transactions, or (ii) Emera does not receive payment in full of the Final Instalment of the Convertible Debentures, Emera intends to pay any shortfall by drawing on the Acquisition Credit Facilities and/or using existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) or other sources available to Emera in order to consummate the Acquisition. See "Summary—Financing the Acquisition."

The unaudited pro forma consolidated financial statements have been prepared using certain of the Company's and TECO Energy's respective financial statements as more particularly described in the notes to such unaudited pro forma consolidated financial statements. In preparing such unaudited pro forma consolidated financial statements, Emera has had limited access to the non-public books and records of TECO Energy and makes no representation or warranty as to the accuracy or completeness of such information provided by TECO Energy, including the financial statements of TECO Energy that were used to prepare the unaudited pro forma consolidated financial statements. The unaudited pro forma combined financial information included in this Prospectus has not been prepared in compliance with Regulation S-X.

Such unaudited pro forma consolidated financial statements are not intended to be indicative of the results that would actually have occurred, or the results expected in future periods, had the events reflected herein occurred on the dates indicated. Actual amounts recorded upon the finalization of the purchase price allocation under the Acquisition may differ from such unaudited pro forma consolidated financial statements. Since the unaudited pro forma consolidated financial statements have been developed to retroactively show the effect of transactions that are expected to occur at a later date (even though this was accomplished by following generally accepted practice using reasonable assumptions), there are limitations inherent in the very nature of pro forma data. The data contained in the unaudited pro forma consolidated financial statements represents only a simulation of the potential impact of the Acquisition. Undue reliance should not be placed on such unaudited pro forma consolidated financial statements. See "Special Note Regarding Forward-Looking Statements" and "Risk Factors."

CURRENCY

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to “Canadian dollars”, “$”, “CAD” or “Cdn$” are to lawful currency of Canada. References to “U.S. dollars”, “USD”, “US$” or “U.S.$” are to lawful currency of the United States of America.

The following table sets forth, for each of the periods indicated, the noon exchange rate, the average noon exchange rate and the high and low noon exchange rates of one U.S. dollar in exchange for Canadian dollars as reported by the Bank of Canada.

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
High	1.4589	1.2803	1.3990	1.1643	1.0697
Low	1.2962	1.1728	1.1728	1.0614	0.9839
Average	1.3732	1.2412	1.2787	1.1045	1.0299
Period End	1.2971	1.2683	1.3840	1.1601	1.0636

On June 7, 2016, the noon exchange rate as reported by the Bank of Canada was U.S.$1.00 = $1.2789.

THIRD PARTY SOURCES AND INDUSTRY DATA

This Prospectus contains information from publicly available third party sources as well as industry data prepared by the Company's management on the basis of its knowledge of the regulated electric and gas utility industry in which Emera operates (including management's estimates and assumptions relating to the industry based on that knowledge). Emera's management's knowledge of the regulated utility industry has been developed through its experience and participation in the industry. Emera's management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness of this data. Third-party sources generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of included information. Although Emera's management believes it to be reliable, Emera has not independently verified any of the data from third-party sources referred to in this Prospectus or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information and financial data and statements appearing elsewhere in this Prospectus and in the documents incorporated by reference herein.

Unless otherwise indicated by the context, the terms "Emera," the "Company," "we," "our," and "us" refer to Emera Incorporated, and, if the context requires, its subsidiaries.

Unless otherwise indicated by the context, the term "TECO Energy" refers to the holding company TECO Energy, Inc. and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries.

Unless otherwise indicated by the context, the term "Acquisition" refers to the acquisition by Emera of TECO Energy pursuant to the terms of the Acquisition Agreement.

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to "Canadian dollars," "$," "CAD" or "Cdn$" are to lawful currency of Canada. References to "U.S. dollars," "USD", "U.S.$" or "US$" are to lawful currency of the United States of America.

Please refer to the "Glossary" beginning on page 40 of this Prospectus for a list of defined terms used herein.

Company Overview

Emera

Emera is a geographically diverse energy and services company headquartered in Halifax, Nova Scotia with approximately Cdn$11.5 billion in assets as of March 31, 2016 and 2015 revenues of Cdn$2.79 billion. Emera invests in electricity generation, transmission and distribution, gas transmission and utility services. Emera currently provides regional energy solutions by connecting its assets, markets and partners in eastern Canada, northeastern United States and the Caribbean. Emera's business continues to grow and evolve. Meeting customer demand for cleaner affordable energy remains central to Emera's strategy.

Key Lines of Business

Utilities

Regulated utilities are the foundation of Emera's business, providing the company with strong and consistent earnings. From its beginnings as NS Power Holdings Incorporated in 1998 following the privatization of Nova Scotia Power Corporation in 1992, Emera has grown by investing in its businesses, and through strategic acquisitions. Emera became an international business with the acquisition of Bangor Hydro in 2001, and expanded its investment in the State of Maine by adding Maine & Maritimes Corporation in 2010. In the Caribbean, Emera has built a business of scale, starting with its investment in St. Lucia's electric utility in 2007, and now holding an indirect majority ownership interest in electric utilities in Grand Bahama and Dominica and a 100% indirect ownership interest in The Barbados Light & Power Company Limited.

At the core of Emera's utilities strategy is identifying opportunities to invest in the transition from higher carbon methods of electricity generation to lower carbon alternatives. NSPI has invested in wind energy, biomass and hydroelectricity with the result that in 2015, 27% of NSPI's generation mix was derived from renewable sources, and on track to meet a minimum 40% renewable standard by 2020. In the Caribbean, Emera is similarly focused on introducing cleaner generation alternatives, with an emphasis on affordability and fuel cost stability for its customers.

Transmission

Emera is investing in electricity transmission to help get new renewable energy to market. Emera's leadership in the Maritime Link Project is expected to transform the electricity market in the Atlantic Provinces, enabling growth in the availability of clean, renewable energy for the region. In addition, the Atlantic Provinces will be connected to the Northeastern United States, providing potential for excess renewable energy to be delivered throughout that region.

Non-regulated

Since its formation in 2003, Emera Energy has become an active participant in the Northeastern United States electricity and natural gas marketplace. It has built a strong marketing, trading and asset management business, based on comprehensive market knowledge, a focus on customer service and robust risk management. The integration and performance of the three New England Gas Generation Facilities purchased in 2013 has contributed significantly to the success of Emera Energy. Emera Energy has invested to improve the performance of its natural gas generation assets in New England, creating long-term value for its business.

As it has grown, Emera has held true to the core values that guide its business: building relationships by acting with integrity, focusing on operations and service excellence, investing in its people, and making safety and health its foremost priority. For more information on Emera's business operations, see "Business".

Emera's Segments

Emera manages its reportable segments separately due to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contributions of revenues, net income attributable to common shareholders and total assets. As of March 31, 2016, Emera had the following six reportable segments: NSPI, Emera Maine, Emera Caribbean, Pipelines, Emera Energy and Corporate and Other.

Nova Scotia Power Inc.

NSPI was created in 1992 through the privatization of the Crown corporation, Nova Scotia Power Corporation. NSPI is a fully-integrated regulated electric utility and is the primary electricity supplier in Nova Scotia, Canada. As of March 31, 2016 NSPI has Cdn$4.6 billion of assets and provides electricity generation, transmission and distribution services to approximately 507,000 customers. NSPI owns 2,483 megawatts ("MW") of generating capacity, of which approximately 50% is coal-fired; 28% of which is natural gas and/or oil; 19% of which is hydro and wind and 3% of which is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own and operate 496 MW of wind and biomass fueled generation capacity, which is expected to increase to 552 MW by the end of 2016. NSPI also owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities. NSPI has a workforce of approximately 1,700 people. NSPI is a public utility as defined in the *Public Utilities Act* (Nova Scotia) (the "Public Utilities Act") and is subject to regulation under the Public Utilities Act by the Nova Scotia Utility and Review Board (the "UARB"). The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time at its request or at the UARB's request.

NSPI is regulated under a cost-of-service model, with rates established to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. NSPI has a fuel adjustment mechanism ("FAM"), approved by the UARB, allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between prudently incurred fuel for generation and purchased power and certain fuel-related 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.

Emera Maine

Emera Maine is a transmission and distribution ("T&D") electric utility with assets of approximately Cdn$1.1 billion serving approximately 158,000 customers in the State of Maine (as of March 31, 2016). Effective January 1, 2014, Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS") merged, becoming Emera Maine.

Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine's T&D networks. Emera Maine owns and operates approximately 1,700 kilometres of transmission facilities and 15,000 kilometres of distribution facilities. Emera Maine's workforce is approximately 400 people.

Approximately 55% of Emera Maine's electric revenue represents distribution operations, 31% is associated with local transmission operations and 14% relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC.

There are two transmission districts in Emera Maine: Bangor Hydro District and MPS District, each of which correspond to the service territories of the two pre-merger entities.

Local transmission rates for Bangor Hydro District (the franchise electric service territory associated with the former Bangor Hydro Electric Company in portions of the Maine counties of Penobscot, Hancock, Washington, Waldo, Piscataquis, and Aroostook) are regulated by the FERC and set annually on June 1, based on a formula utilizing prior year actual transmission investments, adjusted for current year forecasted transmission investments. The Bangor Hydro District's bulk transmission assets are managed by ISO-NE as part of a region-wide pool of assets. ISO-NE manages the region's bulk power generation and transmission systems and administers the open access transmission tariff. Currently, the Bangor Hydro District, along with all other participating transmission providers, recovers the full cost of service for its transmission assets from the customers of participating transmission providers in New England, based on a regional FERC approved formula that is updated June 1 each year.

Local transmission rates for MPS District (the franchise electric service territory associated with the former Maine Public Service Company in the Maine counties of Aroostook and a portion of Penobscot) are regulated by the FERC and are set annually on June 1 for wholesale and July 1 for retail customers, based on a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted investments. The MPS District electric service territory is not connected to the New England bulk power system and it is not a member of ISO-NE.

Emera Caribbean

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

- 100% (December 31, 2015 – 95.5%) investment in Emera (Caribbean) Incorporated ("ECI") and its wholly owned subsidiary Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and the provider of electricity on the island of Barbados, serving approximately 126,000 customers and regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. BLPC owns 239 MW of oil-fired generation, 116 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC has a workforce of 330 people. BLPC is regulated under a cost-of-service model with rates set to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner.

- 50.0% direct and 30.4% indirect interest (through a 60.7% interest in ICD Utilities Ltd. ("ICDU") in Grand Bahama Power Company Ltd. ("GBPC"), which is a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves approximately 19,000 customers. GBPC owns 98 MW of oil-fired generation, 138 kilometres of transmission facilities and 850 kilometres of distribution facilities and has a workforce of 205 people. GBPC is regulated by Grand Bahama Port Authority ("GBPA"), which has granted GBPC a licensed, regulated and exclusive franchise to generate, transmit and distribute electricity on the island until 2054. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner.
- 51.9% (December 31, 2015 – 49.6%) indirect controlling interest, through ECI, in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica. Domlec serves approximately 36,000 customers and is regulated by the Independent Regulatory Commission, Dominica. Domlec owns 20 MW of oil-fired generation, 7 MW of hydro production, 452 kilometres of transmission facilities and 640 kilometres of distribution facilities. Domlec has a workforce of 238 people. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base for 2016 is 15.0%. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.
- 19.1% indirect interest, through ECI, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia, which is regulated by the Government of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Pipelines

Pipelines comprises Emera's wholly owned Brunswick Pipeline and Emera's 12.89% interest in M&NP.

- Brunswick Pipeline is a 145-kilometre pipeline delivering re-gasified natural gas from the Canaport™ liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States for Repsol Energy Canada under a 25-year firm service agreement which expires in 2034. The NEB, which regulates Brunswick Pipeline, has classified it as a Group II pipeline. The agreement is accounted for as a direct financing lease.
- M&NP is a 1,400-kilometre transmission pipeline built to transport natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States. The investment in M&NP is accounted for on the equity basis.

Emera Energy

Emera Energy includes the following:

- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business.
- Emera Energy Generation ("EEG"), consisting of a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada with 1,410 MW of total capacity.

- Emera's 50.0% joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.

Corporate and Other

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

Other includes various consolidated and non-consolidated investments, including:

Consolidated Investments

- Emera Utility Services, which is a utility services contractor primarily operating in Atlantic Canada.
- Emera Reinsurance Limited, which is a captive insurance company providing insurance and reinsurance to Emera and its affiliates.

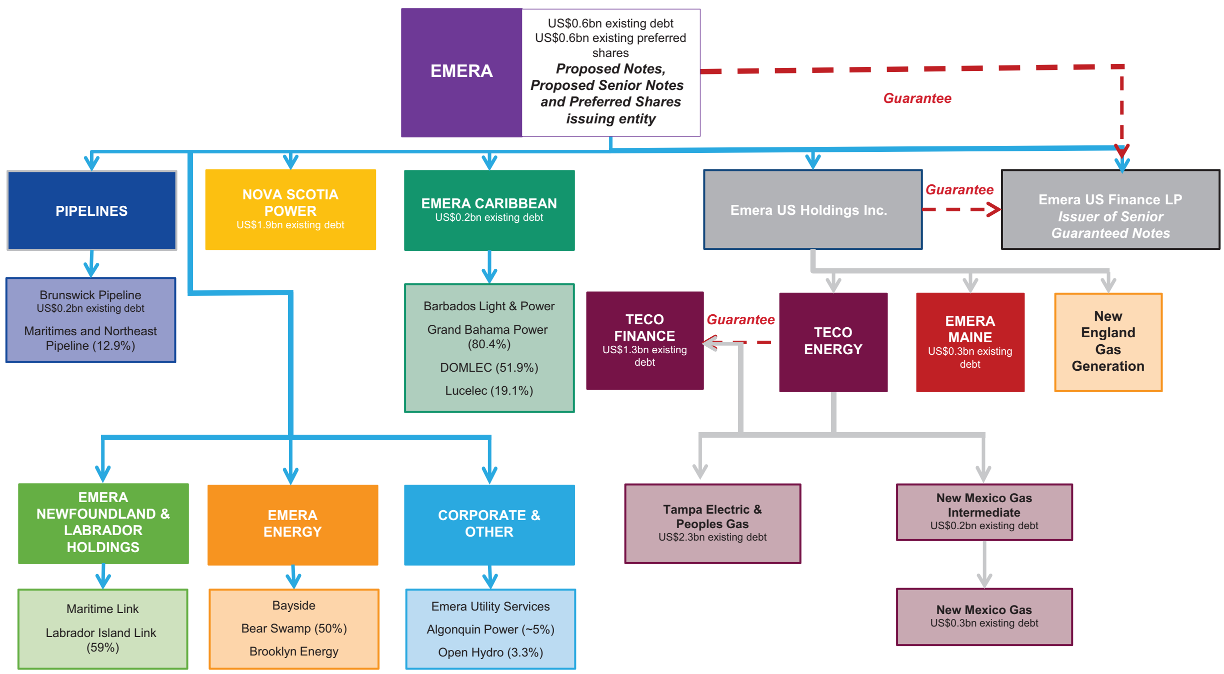
Non-consolidated Investments

- Emera's 4.75% (March 31, 2016: 23.2%) investment in APUC. APUC is a diversified generation, transmission and distribution utility traded on the Toronto Stock Exchange ("TSX") under the symbol "AQN," the distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate-regulated electric transmission and natural gas pipeline systems in the United States and Canada. For information regarding Emera's recent sale of a portion of its ownership interest in APUC, see "Summary—Recent Developments."
- Emera's 100% investment in Emera Newfoundland and Labrador Holdings, Incorporated ("ENL"), which holds investments in the following:
  - Emera's 100% investment in NSP Maritime Link Incorporated ("NSPML"), a $1.56 billion transmission project, including two 170-kilometre subsea cables, between the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the return on equity component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017.
  - Emera's 59.0% (December 31, 2015 – 55.5%) investment in the partnership capital of Labrador Island Link Limited Partnership ("LIL"), a $3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49% of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017. Emera's total investment is expected to approximate Cdn$409.1 million.
- Other investments.

Organizational Structure

The following chart provides a summary of Emera's organizational structure as of December 31, 2015 on a pro forma basis after giving effect to the Acquisition. The chart depicts (i) Emera's reportable segments (including consolidated and non-consolidated investments) and (ii) selected subsidiaries of Emera.

Simplified Pro Forma Organization Chart



Notes:
(1) Organizational chart based on segments outlined in "Management's Discussion and Analysis."

Business Strategy

Emera's business strategy consists of the following key components:

Focus on identifying reliable and affordable energy solutions, typically including the replacement of higher carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver energy to that market

- Emera is investing Cdn$2.2 billion to build the Maritime Link and associated projects, which will bring clean hydro energy from Labrador to Nova Scotia, and create opportunities for surplus renewable energy to supply other markets.
- NSPI has invested in wind energy, biomass and hydroelectricity, which has driven substantial increases in the portion of its generation mix derived from renewable sources (reaching 27% in 2015 and on track to meet its 40% target by 2020).
- Numerous other investments and initiatives are underway, from a new utility grade solar facility in Barbados to the Maine Renewable Energy Interconnect ("MREI") transmission proposal, designed to deliver new wind energy in northern Maine to markets in southern New England.

Develop strong partnerships and relationships throughout the regions in which we operate and utilize a collaborative approach to strategic partnerships

- The foundation of Emera's strategy is its collaborative approach to strategic partnerships and its ability to develop strong relationships throughout the regions in which it operates. Prime examples of Emera's success in this areas include:
  - The Maritime Link project, where Emera and its partner Nalcor, along with the Government of Canada and the Provinces of Nova Scotia and Newfoundland and Labrador, have entered into numerous agreements and partnerships to deliver and finance the Maritime Link, the Labrador Island Link and the related Muskrat Falls project.
  - Emera's Strategic Investment Agreement ("SIA") with APUC establishes how Emera and APUC will work together to pursue specific strategic investments of mutual benefit. While Emera recently announced that it has reduced its direct investment in APUC, the SIA remains in place as both companies value the partnership. See "Summary—Recent Developments."
  - Emera has a number of other partnerships and collaborative agreements across its operating regions, including a joint dispatch project between NSPI and New Brunswick Power Corporation ("NB Power"), a partnership between Emera Maine and Central Maine Power Company to develop the MREI, and the Massachusetts Clean Electricity Partnership, an alliance including Brookfield Renewable Partners, Hydro-Québec, Nalcor, NB Power, SunEdison and TDI New England to promote clean energy investments in New England.

Establish a diverse investment and operations profile

- Emera is a geographically diverse company, operating in Canada, the United States, and the Caribbean.
- Its operations include:
  - vertically integrated electric utilities in Nova Scotia, Barbados, Dominica and Grand Bahama;
  - a transmission and distribution electric utility in Maine;
  - a portfolio of generation facilities, including combined-cycle natural gas and pumped storage hydro in Atlantic Canada and the U.S. northeast;
  - investments in two natural gas pipelines in Atlantic Canada and New England;
  - natural gas marketing and trading;
  - a utility services contractor in Atlantic Canada;
  - a Cdn$2.2 billion project to bring clean hydro energy from Labrador to Nova Scotia; and
  - minority interests in numerous energy projects and companies.

Employ operating and governance models that focus on operational excellence, constructive regulatory approaches, proactive stakeholder engagement and a customer focus through service reliability and rate stability

- Emera's focus on maintaining the highest standards of governance practices is evident in a number of ways including, for example:
  - The Maritime Link project's on time and on budget record, notwithstanding the ambitious and ground-breaking nature of the project, the changing economic climate during the course of the project, and the challenge other similar projects have had with budget and schedule;

- Emera's consistently high ranking (2nd overall in 2015) in a survey of governance practices among Canada's publicly traded companies, conducted each year by the Globe & Mail's Report on Business; and
- The establishment of operating boards for Emera's subsidiaries, and the inclusion of local business and community leaders on these boards as well as Emera executives. This practice has helped Emera develop constructive regulatory approaches, proactive stakeholder engagement and maintain a customer focus in its businesses in each of the markets it operates in.

Competitive Strengths

We believe we have the following key competitive strengths to enable us to carry out our business strategy.

Diverse, increasingly regulated profile

- The portion of Emera's adjusted net income generated from rate regulated business has grown from 67% in 2014 to 72% in the 12 months ended March 31, 2016. On a pro forma basis, the Acquisition will bring Emera's regulated earnings to greater than 80%.
- Emera targets achieving 75% to 85% of its adjusted net income from rate-regulated subsidiaries, which contribute strong, predictable income and cash flows, and which is reflective of Emera's risk tolerance.

Supportive and stable regulatory environments

- Through its long history of operating regulated businesses, Emera has gained an appreciation for the importance of constructive, professional regulatory oversight. Emera's experience in jurisdictions such as Nova Scotia and Maine, where it has built robust regulatory teams and practices, was a significant factor in making stable regulatory environments a key criteria in its assessment of growth opportunities, including the Acquisition.

Strong balance sheet, cash flow and liquidity position

- Over the last 10 years, Emera's strong balance sheet, and its ability to raise the capital necessary to fund investments has been a strong enabler of its growth. This was demonstrated in Emera's issue of the Convertible Debentures represented by instalment receipts in connection with the Acquisition.
- In addition to access to debt and equity capital markets, cash flow from operations has grown substantially, from Cdn$419 million for the year ended December 31, 2010 to approximately Cdn$674 million for the year ended December 31, 2015.
- Emera and its subsidiaries maintain strong credit metrics, and Emera has consistently maintained a strong, investment grade credit rating, which is an important component of Emera's financing strategy.

Sizeable capital investment plan to drive growth

- Emera has a Cdn$4.2 billion capital investment plan over the next five years, a significant portion of which is related to the Maritime Link and Labrador Island Link projects.
- This capital plan increases to Cdn$8.3 billion, on a pro forma basis, when TECO Energy's US$4.1 billion in planned capital investments are included.

Disciplined investment criteria

- Emera's focused growth strategy and disciplined investment criteria has served it well. Throughout the period of declining interest rates, its investment hurdle rate has remained unchanged, ensuring that any investment met long term criteria.
- Similarly, Emera's strategic target of earning 75-85% of its adjusted net income from rate-regulated subsidiaries meant that the search for growth opportunities in 2014 and 2015 was focused on rate-regulated businesses.

The Acquisition

Acquisition Overview

On September 4, 2015, Emera announced a definitive agreement for Emera to acquire TECO Energy. TECO Energy shareholders will receive U.S.$27.55 per common share of TECO Energy, which represents an aggregate purchase price of approximately U.S.$10.6 billion and which includes the assumption of approximately U.S.$4.1 billion of debt. The closing of the Acquisition is subject to certain conditions, including, among others, (i) approval of TECO Energy shareholders representing a majority of the outstanding shares of TECO Energy common stock (which approval was obtained at the special meeting of shareholders held on December 3, 2015), (ii) approvals by the New Mexico Public Regulation Commission (the "NMPRC"), (iii) the absence of any law or judgment that prevents, makes illegal or prohibits the closing of the Acquisition, (iv) the absence of any material adverse effect with respect to TECO Energy and (v) subject to certain exceptions, the accuracy of the representations and warranties of, and compliance with covenants by, each of the parties to the Acquisition Agreement.

On April 11, 2016, Emera and TECO Energy filed with the NMPRC an unopposed stipulation agreement reflecting a settlement reached with certain intervening parties in the acquisition case currently pending before the NMPRC for approval of the Acquisition. In the stipulation, the parties state that they believe the settlement is in the public interest and have recommended approval to the NMPRC. Amongst other elements, the stipulation includes Emera's agreement to maintain the commitments made by TECO Energy in its 2014 case relating to its acquisition of New Mexico Gas Company ("NMGC"), invest in the expansion of the natural gas system to underserved communities and the Mexican border, and provide resources to support certain economic growth projects and programs. The stipulation is subject to review and approval by the NMPRC. On May 2, 2016 the hearing examiner held a hearing in connection with the joint application to the NMPRC of the change in control of NMGC affected by the Acquisition. A final order of the NMPRC is expected in mid-2016. The closing of the Acquisition is currently expected to occur in mid-2016, although there can be no assurance the Acquisition will occur within the expected timeframe, as contemplated, or at all.

To finance a portion of the Acquisition, Emera, through the Selling Debentureholder, on September 28, 2015, completed the sale of $1.9 billion of Convertible Debentures (the "Convertible Debenture Offering"). On October 2, 2015, in connection with the Convertible Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Convertible Debentures at the Convertible Debenture offering price. The sale of the additional Convertible Debentures brought the aggregate proceeds of the Convertible Debenture Offering to $2.185 billion, assuming payment of the final instalment. See "Description of Other Indebtedness—Convertible Debenture Offering." Additionally, on May 24, 2016, Emera sold a portion of its ownership interest in APUC. See "Management's Discussion and Analysis—Recent Developments."

TECO Energy is a utility holding company headquartered in Tampa, Florida engaged through its subsidiaries in the regulated vertically-integrated electric utility business in Florida and natural gas transmission and distribution business in Florida and New Mexico. TECO Energy's operating revenue in fiscal 2015 totalled approximately

U.S.$2.7 billion and for the three-month period ended March 31, 2016 totalled approximately U.S.$659.5 million. As at March 31, 2016, TECO Energy had total assets of approximately U.S.$9.0 billion. Virtually all of TECO Energy's operating revenue is from regulated businesses.

The offering of any series of Notes hereunder is not contingent upon the completion of the Acquisition, which, if completed may occur subsequent to certain offerings hereunder.

Giving effect to the Acquisition as if it closed on March 31, 2016, the Company's total assets would have increased from approximately Cdn$11 billion (U.S.$9 billion) to approximately Cdn$28 billion (U.S.$21 billion) and the percentage of its EBITDA that is regulated EBITDA would have increased from approximately 70% to over 90% (excluding Emera Corporate and Other (except for ENL) and TECO Energy discontinued operations, TECO Energy Corporate and Other). See "Unaudited Pro Forma Consolidated Financial Statements." The Acquisition is expected to increase the Company's consolidated rate base by approximately U.S.$6.5 billion and its total customers by approximately 1.6 million. Following the Acquisition, the regulated utility subsidiaries of Emera will serve approximately 2.5 million customers.

TECO Energy Overview

TECO Energy was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company ("TEC"). TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of TEC and, through its subsidiary, New Mexico Gas Intermediate, Inc. ("NMGI"), NMGC. TECO Energy and its subsidiaries had approximately 3,700 employees as of March 31, 2016.

TEC, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its Tampa Electric division provided retail electric service to approximately 725,000 customers on average in West Central Florida for the three months ended March 31, 2016, and has a net winter system generating capacity of 4,730 MW. PGS, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With approximately 365,000 customers on average for the three months ended March 31, 2016, PGS has operations in Florida's major metropolitan areas and most populous counties including: Miami-Dade, Broward, Palm Beach, Hillsborough and Orange. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2015 was almost 1.8 billion therms.

NMGC, a Delaware corporation and wholly-owned subsidiary of NMGI, was acquired by TECO Energy on September 2, 2014. NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico. With approximately 520,000 customers on average for the three months ended March 31, 2016, NMGC serves approximately 60% of the state's population in 23 of New Mexico's 33 counties. NMGC's largest concentration of customers (approximately 360,000) is in the region known as the Central Rio Grande Corridor, which includes the communities of Albuquerque, Belen, Rio Rancho and Santa Fe.

New Mexico Gas

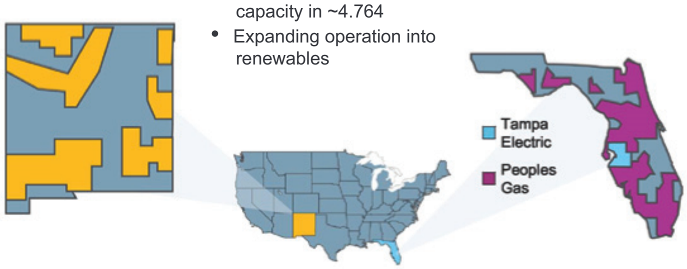
- Regulated gas utility
- Largest gas utility in New Mexico
- Serves almost 520,000 customers
- Expected rate base growth of ~5%
- ~12,000 pipeline miles

Tampa Electric

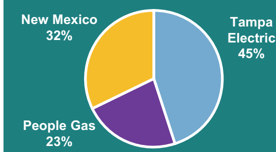
- Regulated gas utility
- Serves 725,000 customers in West Central Florida
- Owns and operates three power plants located in Florida
- Expected rate base growth of more than 10% through 2017, and more than 6% through 2019
- Total generation fleet capacity in ~4.764
- Expanding operation into renewables

Peoples Gas

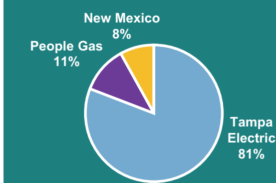
- Regulated gas utility
- Largest gas utility in Florida
- Serves almost 365,000 customers in all major metropolitan areas of the state
- 2014 annual gas throughput of ~1.8bn therms
- ~19,000 pipeline miles



Business Mix



Total customers: ~1,610,000



Total rate base[1] USD$6.5bn

1 Tampa Electric and Peoples Gas average rate base based on earnings surveillance reports filed with FPSC for Dec. 2015. NMGC rate base as of Dec. 31, 2015.

Sale of TECO Coal

On September 21, 2015, TECO Diversified, a wholly-owned subsidiary of TECO Energy, entered into a securities purchase agreement for the sale of TECO Coal to Cambrian Coal Corp. The securities purchase agreement did not provide for an up-front purchase payment, but provides for contingent payments of up to U.S.$60 million that may be paid in the years up to 2019 depending on specified coal benchmark prices. TECO Energy retains certain deferred tax assets and personnel related liabilities, but all other TECO Coal assets and liabilities were transferred in the transaction. The retained liabilities included pension liability, which was fully funded at September 30, 2015, and severance agreements, which were paid in 2015. In addition, TECO Energy retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia. TECO Energy is working with the purchaser and the respective permitting agencies to have all permits transferred to the purchaser by the end of 2016.

The securities purchase agreement called for a simultaneous signing and closing, which occurred on September 21, 2015. The closing of this sale essentially completed the process of TECO Energy's exit from unregulated operations to focus on regulated utility businesses.

As a result of the authorization by TECO Energy's Board of Directors authorizing it to enter into negotiations for the sale of TECO Coal, effective in the third quarter of 2014 it was classified as asset held for sale and its results for all periods presented are classified on TECO Energy's financial statements as discontinued operations. TECO Energy recorded a non-cash valuation adjustment of approximately U.S.$76 million, after tax, to the carrying value of TECO Coal to reflect the sales price specified under a sales agreement entered into in October 2014, and an additional U.S.$51 million impairment charge, including a U.S.$7.7 million charge related to black lung liabilities was recorded in 2015.

Acquisition Highlights

The Acquisition will propel Emera into a top 20 North American regulated utility as ranked by asset size, with geographic diversity and significant growth potential. TECO Energy represents an accretive opportunity for Emera to further diversify its regulated assets, net income and cash flows in growth markets and constructive regulatory environments, while furthering its strategic objective to supply customers with generation from cleaner sources. Features of the Acquisition and TECO Energy business include:

- **Accretive to Earnings, Growth and Scale**. Management expects the Acquisition to be accretive to Emera's earnings per Common Share and to provide support for Emera's dividend growth target through and beyond 2019 and to improve Emera's long-term growth due to the favourable growth profile of the Florida and New Mexico economies and constructive regulatory environments. As a result of the Acquisition, Emera will become one of the top 20 largest regulated utility companies in North America as ranked by asset size, helping to ensure access to equity and debt capital markets and economies of scale.
- **Acquisition of a Pure-Play Regulated Utility—Increase in Regulated Net Income**. Following the closing of the acquisition of TECO Energy, a utility holding company with virtually all of its net income derived from regulated businesses, the percentage of Emera's net income that is derived from regulated business is expected to increase from approximately 70% to over 80% (excluding Emera Corporate and Other (except for ENL) and TECO Energy discontinued operations, TECO Energy Corporate and Other).
- **Increase in Diversification**. The Acquisition will help Emera diversify net income across several regulatory jurisdictions, geographies and business lines. Emera anticipates that this increased diversification in net income derived from regulated businesses will enhance the stability of net income (partially due to complementary seasonality) and overall quality of cash flows, and should also assist in strengthening its credit profile.
- **Constructive Regulatory Jurisdictions**. The majority of TECO Energy's earnings are derived from Florida, which is a constructive regulatory environment. The Florida Public Service Commission (the "FPSC") regulates the operations of Tampa Electric and PGS in Florida. In addition, Tampa Electric has a fuel recovery clause and PGS has recovery clauses in place for purchased gas and cast iron and bare steel pipe replacement, as well as higher increased fixed monthly customer charges that reduce volume sensitivity. NMGC, TECO Energy's gas operations located in New Mexico, is regulated by the NMPRC, which allows for the basic costs, excluding purchased gas, storage and interstate capacity, to be provided for through rates. NMGC has a purchased gas adjustment clause ("PGAC") which allows it to recover the cost of purchased gas on a timely basis.
- **Rate Base Growth Through Capital Investment.** TECO Energy's continued investment in its gas and electric businesses to support customer growth, system reliability and facilities is expected to drive rate base growth over the next several years. Over the long term, Emera believes there is an opportunity to participate in the shift in generation from high carbon sources to low carbon sources as Tampa Electric moves from coal-fired generation to a diversified portfolio of generation that includes gas-fired generating capacity and renewable energy sources.
- **Favourable Florida Economic Indicators**. Florida is the third most populous state in the United States and ranks as the fourth largest economy in the United States. According to the Florida Office of Economic & Demographic Research, job growth and improvements in the housing market are expected to contribute to the growth of Florida's economy and GDP growth is forecast to continue through 2016, with an expected increase of 3.4%.

- **Favourable New Mexico Economic Indicators**. New Mexico is the 36th most populous state in the United States. Sustained job growth of approximately 10,000 jobs per year is forecast through 2017 and the current forecast of GDP growth in 2016 in New Mexico is 2.5% as forecasted by the University of New Mexico Bureau of Business & Economic Research.
- **Experienced Management Team**. TECO Energy's management has a demonstrated track record of working productively with regulators and policy makers, employing a customer focus and regulatory management philosophy in its operating geographies that results in timely recovery of costs and returns on its capital employed. Emera believes that TECO Energy and Emera have complementary management teams and corporate cultures focused on safety and customer service that will facilitate the combination of Emera and TECO Energy following completion of the Acquisition.
- **Community and Stakeholder Engagement**. Emera's approach to combining newly-acquired entities with existing operations is premised on creating value for customers, continuing to invest in the communities in which the acquisition entities operate and aligning Emera's management team and employee base with those of the acquisition entities. Emera intends to continue to invest in local communities in Florida and New Mexico where TECO Energy operates, to preserve TECO Energy's existing headquarter locations and local boards of directors in each state and to retain TECO Energy's existing management team, allowing local managers to be responsive to employees, customers and regulators.

Financing the Acquisition

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) the proceeds from the Acquisition Capital Markets Transactions, including the offering of any Notes pursuant to one or more Prospectus Supplements, (ii) the receipt of payment in full on the Final Instalment Date of the Final Instalment due under the Convertible Debentures, (iii) amounts drawn under the Acquisition Credit Facilities, if any, and (iv) existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) and other sources available to the Company.

In connection with financing the Acquisition, in addition to the offering by Emera of any series of Notes pursuant to one or more Prospectus Supplements, Emera US Finance intends to issue Senior Guaranteed Notes. In addition, Emera intends to issue one or more series of Canadian dollar-denominated unsecured senior notes, and may also issue Canadian dollar-denominated unsecured subordinated notes, in each case, on a basis which is exempt from the prospectus requirements of applicable Canadian securities laws. These offerings are collectively referred to herein as the "Acquisition Capital Markets Transactions." Emera intends to raise up to approximately Cdn$6.6 billion in aggregate principal amount in the Acquisition Capital Markets Transactions. The aggregate principal amounts raised in the Acquisition Capital Markets Transactions and the terms on which such securities are issued are dependent on market and other conditions and may vary. Nothing contained herein shall be deemed to constitute an offer to sell or a solicitation of an offer to buy any of the securities to be issued in the Acquisition Capital Markets Transactions other than any Notes offered hereunder.

The closing of any offering of any series of Notes hereunder is not contingent upon the consummation of the Acquisition, the other Acquisition Capital Markets Transactions or payment in full of the Final Instalment of the Convertible Debentures. To the extent (i) Emera raises less than Cdn$6.6 billion in connection with the Acquisition Capital Markets Transactions, or (ii) Emera does not receive payment in full of the Final Instalment of the Convertible Debentures, Emera intends to pay any shortfall by drawing on the Acquisition Credit Facilities and/or using existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) or other sources available to Emera in order to consummate the Acquisition.

The net proceeds of any offering of Notes will be used as set forth in the applicable Prospectus Supplement. Such uses may include financing directly or indirectly, part of the purchase price payable for the Acquisition (including Acquisition-Related Expenses) and to reduce amounts outstanding under the Acquisition Credit Facilities established in favour of Emera to fund the purchase price payable for the Acquisition, to the extent any amounts are drawn on such facilities in connection with the Acquisition.

See “Use of Proceeds” for information concerning the use of proceeds of offerings hereunder, “Description of Other Indebtedness” for information concerning the Subordinated Notes, the Acquisition Credit Facilities and the Revolving Facility, and “Risk Factors” for a discussion of certain risks relating to the financing of the Acquisition.

Recent Developments

On May 17, 2016, Emera announced that it had agreed to sell all of its 50.1 million common shares of APUC representing approximately 19.3% of the issued and outstanding common shares, to a syndicate of underwriters at Cdn$10.85 per common share, for an aggregate gross amount of approximately Cdn$544 million. The sale was completed on May 24, 2016. Emera intends to use the net proceeds from the sale in support of its general financing requirements, including the Acquisition. Emera continues to hold an equity interest in APUC equivalent to approximately 12.9 million common shares (in the form of subscription receipts and dividend equivalents), which upon conversion represent a continuing common equity interest of approximately 4.75%.

The Notes

The specific terms of any offering of the Notes will be set forth in one or more Prospectus Supplements. You should read this Prospectus and any applicable Prospectus Supplement before you invest in any Notes.

Issuer:	Emera Incorporated, a company formed under the *Companies Act* (Nova Scotia).
Offering:	Unsecured, subordinated notes of Emera (the "Notes").
Principal Amount of Notes:	Up to U.S.$1,250,000,000 Notes.
Terms of the Notes:	The Notes may be issued in one or more separate series. The Prospectus Supplement relating to the particular series of Notes being offered will specify the particular amounts, prices and terms of those Notes. These terms may include: • the title of the Notes; • any limit on the aggregate principal amount of the Notes of the series; • the date on which the Notes will mature; • the interest rate or rates, or the method of determining those rates; • the date from which interest will accrue or the method for determining such date; • the interest payment dates and the regular record dates; • the places where payments will be made; • any mandatory or optional redemption provisions; • any additions to the events of default or covenants included in the Trust Indenture, as described in this Prospectus; • if other than U.S. dollars, the currency or currencies, or units based on or related to currencies, in which payments on the Notes will be payable; • whether the Notes will be issued in the form of a global security; and • any other specific terms of the Notes
Specified Denominations:	Minimum denominations of U.S.$2,000 and integral multiples of U.S.$1,000 in excess thereof.
Maturity Date:	Each series of Notes will mature sixty (60) years from the date of issue (the "Maturity Date").
Interest:	During the initial ten (10) year period following the issuance of any series of Notes, Emera will pay interest on such Notes at the rate specified in the applicable Prospectus Supplement in equal semi-annual installments.

Starting on the date which is ten (10) years from the date of issuance of any series of Notes, Emera will pay interest on such Notes on a quarterly basis in each year during which such Notes are outstanding thereafter until the Maturity Date (each such semi-annual or quarterly date, as applicable, an “Interest Payment Date”).

From the date of issuance of any series of Notes to, but excluding, the date which is ten (10) years from the date of issuance of such Notes, the interest rate on such Notes will be fixed at the rate specified in the applicable Prospectus Supplement, payable in arrears. Starting on the date which is ten (10) years from the date of issuance of any series of Notes and on every quarterly period thereafter until the Maturity Date (each such date, an “Interest Reset Date”), the interest rate on such Notes will be reset at an interest rate per annum equal to the three month LIBOR plus an additional basis points margin as specified in the applicable Prospectus Supplement. See “Description of the Notes—Interest.”

Deferral Right: . . . . So long as no event of default has occurred and is continuing, Emera may elect, at its sole option, at any date other than an Interest Payment Date (a “Deferral Date”) to defer the interest payable on any series of Notes on one or more occasions for up to five consecutive years (a “Deferral Period”). There is no limit on the number of Deferral Periods that may occur. Such deferral will not constitute an event of default or any other breach under the Trust Indenture and the Notes. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. A Deferral Period terminates on any interest payment date where Emera pays all accrued and unpaid interest on such date. No Deferral Period may extend beyond the maturity date of the series of Notes.

Dividend Stopper Undertaking: . . . . . . Unless Emera has paid all accrued and payable interest on any series of Notes, subject to certain exceptions, Emera will not (i) declare any dividends on the Dividend Restricted Shares or pay any interest on any Parity Notes, (ii) redeem, purchase or otherwise retire Dividend Restricted Shares or Parity Notes, or (iii) make any payment to holders of any of the Dividend Restricted Shares or any Parity Notes in respect of dividends not declared or paid on such Dividend Restricted Shares or interest not paid on such Parity Notes, respectively (the “Dividend Stopper Undertaking”).

“Dividend Restricted Shares” means, collectively, the preferred shares of Emera (including the Conversion Preferred Shares) and the common shares of Emera.

“Parity Notes” means any class or series of Emera indebtedness currently outstanding or hereafter created which ranks on a parity with the Notes (prior to any Automatic Conversion (as defined below)) as to distributions upon liquidation, dissolution or winding-up.

It is in the interest of Emera to ensure that it timely pays interest on the Notes so as to avoid triggering the Dividend Stopper Undertaking. See "Description of the Notes—Dividend Stopper Undertaking" and "Risk Factors."

Automatic Conversion: . . . . Each series of Notes, including accrued and unpaid interest thereon, will be converted automatically ("Automatic Conversion"), without the consent of the holders thereof, into shares of a newly issued series of First Preferred Shares of Emera (the "Conversion Preferred Shares") upon the occurrence of: (i) the making by Emera of a general assignment for the benefit of its creditors or a proposal (or the filing of a notice of its intention to do so) under the *Bankruptcy and Insolvency Act* (Canada), (ii) any proceeding instituted by Emera seeking to adjudicate it a bankrupt or insolvent, or, where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent, (iii) a receiver, interim receiver, trustee or other similar official is appointed over Emera or for any substantial part of its property and assets by a court of competent jurisdiction in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada; or (iv) any proceeding is instituted against Emera seeking to adjudicate it a bankrupt or insolvent or, where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada, and either such proceeding has not been stayed or dismissed within sixty (60) days of the institution of any such proceeding or the actions sought in such proceedings occur, including the entry of an order for relief against Emera or the appointment of a receiver, interim receiver, trustee, or other similar official for it or for any substantial part of its property and assets (each, an "Automatic Conversion Event").

The Automatic Conversion shall occur upon an Automatic Conversion Event (the "Conversion Time"). As of the Conversion Time, each series of Notes shall be automatically converted, without the consent of noteholders, into a newly issued series of fully-paid Conversion Preferred Shares. At such time, such series of Notes shall be deemed to be immediately and automatically surrendered and cancelled without need for further action by noteholders, who shall thereupon automatically cease to be holders thereof and all rights of any such holder as a debtholder of Emera shall automatically cease. At the Conversion Time, holders of each series of Notes will receive one Conversion Preferred Share for each U.S.$1,000 principal amount of Notes previously held together with the number of Conversion Preferred Shares (including fractional shares, if applicable) calculated by dividing the amount of accrued and unpaid interest, if any, on the Notes by U.S.$1,000.

Upon an Automatic Conversion of the Notes, Emera reserves the right not to issue some or all, as applicable, of the Conversion Preferred Shares to any person whose address is in, or whom Emera or its transfer agent has reason to believe is a resident of, any jurisdiction outside of Canada and the United States of America to the extent that: (i) the issuance or delivery by Emera to such person, upon an Automatic Conversion of Conversion Preferred Shares, would require Emera to take any action to comply with securities or analogous laws of such jurisdiction; or (ii) withholding tax would be applicable in connection with the delivery to such person of Conversion Preferred Shares upon an Automatic Conversion ("Ineligible Persons"). In such circumstances, Emera will hold all Conversion Preferred Shares that would otherwise be delivered to Ineligible Persons, as agent for Ineligible Persons, and will attempt to facilitate the sale of such shares through a registered dealer retained by Emera for the purpose of effecting the sale (to parties other than Emera, its affiliates or other Ineligible Persons) on behalf of such Ineligible Persons of such Conversion Preferred Shares.

As the events that give rise to an Automatic Conversion are bankruptcy and related events, it is in the interest of Emera to ensure that an Automatic Conversion does not occur, although the events that could give rise to an Automatic Conversion may be beyond Emera's control. See "Description of the Notes—Automatic Conversion," "Description of Conversion Preferred Shares" and "Risk Factors."

Conversion Preferred Shares: .... The Conversion Preferred Shares will carry the right to receive cumulative preferential cash dividends, if, as and when declared by the Board of Directors, subject to the *Companies Act* (Nova Scotia) at the same rate as would have accrued on the related series of Notes (had such Notes remained outstanding) as described under "Descriptions of the Notes—Interest" (the "Perpetual Preferred Share Rate"), payable on each semi-annual or quarterly dividend payment date, as the case may be, subject to any applicable withholding tax. See "Description of Conversion Preferred Shares."

Purchase for Cancellation: .... Subject to the Dividend Stopper Undertaking, each series of Notes may be purchased, in whole or in part, by Emera in the open market or by tender or private contract. Notes purchased by Emera shall be cancelled and shall not be reissued. The purchase price payable by Emera will be paid in cash.

Redemption Right:	Except as may otherwise be provided in a Prospectus Supplement, on or after the date that is ten (10) years from the date of issuance of any series of Notes, Emera may, at its option, on giving not more than 60 nor less than 30 days' notice to the holders of such Notes, redeem the Notes, in whole at any time or in part from time to time on any Interest Payment Date. The redemption price per U.S.$1,000 principal amount of Notes redeemed on any Interest Payment Date will be 100% of the principal amount thereof, together with accrued and unpaid interest to, but excluding, the date fixed for redemption. Notes that are redeemed shall be cancelled and shall not be reissued. See "Description of the Notes—Redemption Right."
Redemption on Tax or Rating Event:	Except as may otherwise be provided in a Prospectus Supplement, prior to the initial Interest Reset Date and within 90 days of a Tax Event, Emera may, at its option, redeem all (but not less than all) of any series of Notes at a redemption price per U.S.$1,000 principal amount of such Notes equal to 100% of the principal amount thereof, together with accrued and unpaid interest to but excluding the date fixed for redemption. See "Description of the Notes—Redemption on Tax or Rating Event." Except as may otherwise be provided in a Prospectus Supplement, prior to the initial Interest Reset Date and within 90 days of a Rating Event, Emera may, at its option, redeem all (but not less than all) of any series of Notes at a redemption price per U.S.$1,000 principal amount of such Notes equal to 102% of the principal amount thereof, together with accrued and unpaid interest to but excluding the date fixed for redemption. See "Description of the Notes—Redemption on Tax or Rating Event."
Additional Optional and Mandatory Redemption Events:	The Prospectus Supplement relating to a particular series of Notes being offered may also include additional optional redemption rights or mandatory redemption events.
Additional Emera Covenants:	In addition to the Dividend Stopper Undertaking, Emera will covenant for the benefit of the holders of each series of Notes that it will not create or issue any Emera Preferred Shares which, in the event of insolvency or winding-up of Emera, would rank in right of payment in priority to the Conversion Preferred Shares.
Subordination and Events of Default:	The Notes will be direct unsecured subordinated obligations of Emera. The payment of principal and interest on the Notes will be subordinated in right of payment to the prior payment in full of all present and future Senior Indebtedness, and will be effectively subordinated to all indebtedness and obligations of Emera's subsidiaries.

"Senior Indebtedness" means obligations (other than non-recourse obligations, Notes issued under the Trust Indenture or any other obligations specifically designated as being subordinate in right of payment to Senior Indebtedness) of, or guaranteed or assumed by, Emera for borrowed money or evidenced by bonds, debentures or notes or obligations of Emera for or in respect of bankers' acceptances (including the face amount thereof), letters of credit and letters of guarantee (including all reimbursement obligations in respect of each of the forgoing) or other similar instruments, and amendments, renewals, extensions, modifications and refunding of any such indebtedness or obligation. As of March 31, 2016, Emera's Senior Indebtedness totaled approximately Cdn$751 million.

An event of default in respect of any series of Notes will occur only if Emera defaults on the payment of (i) principal or premium, if any, when due and payable, or (ii) interest when due and payable and such default continues for 30 days (subject to Emera's right, at its sole option, to defer interest payments, as described under "Description of the Notes—Deferral Right").

If an event of default has occurred and is continuing with respect to a series of Notes, and the Notes have not already been automatically converted into Conversion Preferred Shares, then Emera shall without notice from the Indenture Trustee be deemed to be in default under the Trust Indenture and the Notes and an Indenture Trustee may, in its discretion and shall upon the request of holders of not less than one-quarter of the principal amount of Notes of that series then outstanding under the Trust Indenture, demand payment of the principal or premium, if any, together with any accrued and unpaid interest up to (but excluding) such date, which shall immediately become due and payable in cash, and may institute legal proceedings for the collection of such aggregate amount where Emera fails to make payment thereof upon such demand.

Payment of Additional Amounts: . . . . All payments made by or on account of any obligation of Emera under or with respect to the Notes shall be made free and clear of and without withholding or deduction for, or on account of, any present, or future tax, duty, levy, impost, assessment or other governmental charge (including penalties, interest and other liabilities related thereto) imposed or levied by or on behalf of the Government of Canada or any province or territory thereof or by any authority or agency therein or thereof having power to tax ("Canadian Taxes"), unless Emera is required to withhold or deduct Canadian Taxes by law or by the interpretation or administration thereof by the relevant government authority or agency. If Emera is so required to withhold or deduct any amount for or on account of Canadian Taxes from any payment made under or with respect to the Notes, Emera shall pay as additional interest such additional amounts as may be necessary so that the net amount received by each holder of the Notes after such withholding or deduction shall not be less than the amount such

	holder would have received if such Canadian Taxes had not been withheld or deducted, subject to certain exceptions. See "Description of the Notes—Payment of Additional Amounts."
Book-Entry Only Form:	Each series of Notes will be issued under the book-entry only system operated by The Depository Trust Company or its nominees (the "Clearing Agency") and must be purchased or transferred through participants (collectively, "Participants") in the depository service of the Clearing Agency. Participants include securities brokers and dealers, banks and trust companies. Accordingly, physical certificates representing the Notes will not be available except in the limited circumstances described under "Description of the Notes—Book-Entry Only Form".
Use of Proceeds:	The net proceeds of any offering of Notes will be used as set forth in the applicable Prospectus Supplement. Such uses may include financing, directly or indirectly, part of the purchase price payable for the Acquisition (including Acquisition-Related Expenses) and to reduce any amounts outstanding under the Acquisition Credit Facilities to the extent any amounts are drawn on such facilities in connection with the Acquisition. See "Use of Proceeds".

Corporate Information

Emera was incorporated in the Province of Nova Scotia in 1998. Emera's principal executive office is located at 5151 Terminal Road, P.O. Box 910, Halifax, Nova Scotia B3J 1A1 and Emera's telephone number is (902) 450-0507. Emera's website address is www.emera.com. Material contained on Emera's website is not part of and is not incorporated by reference in this Prospectus.

Summary Historical and Pro Forma Financial Data

Emera Summary Historical Financial Data

The following table shows summary historical financial of Emera for the periods and as of the dates indicated. The summary historical financial data presented as at December 31, 2015 and 2014 and for the year ended December 31, 2015 are derived from the audited financial statements of Emera, which are incorporated by reference in this Prospectus. The selected historical financial data presented as at December 31, 2013 and for the year ended December 31, 2013 are derived from the audited financial statements of Emera, which are not incorporated by reference in this Prospectus. The summary historical financial data presented as of March 31, 2016 and 2015 and for the three months ended March 31, 2016 and 2015 are derived from the unaudited financial statements of Emera, which are incorporated by reference in this Prospectus.

The following summary historical and unaudited financial data should be read in conjunction with "Capitalization" and "Management's Discussion and Analysis" contained herein and Emera's financial statements and related notes incorporated by reference in this Prospectus.

	Emera historical				
	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
Statement of Operations Data:					
Total operating revenues	**877.0**	**888.5**	**2,789.3**	**2,938.6**	**2,230.2**
Total operating expenses	**607.0**	**656.4**	**2,281.6**	**2,271.3**	**1,823.1**
Net income	54.8	174.1	452.4	452.8	255.3
Non-controlling interest in subsidiaries	3.5	6.3	24.9	19.9	18.5
Net income of Emera Incorporated	51.3	167.8	427.5	432.9	236.8
Preferred stock dividends	7.0	7.7	30.3	26.2	19.3
Net income attributable to common shareholders	$ 44.3	$ 160.1	$ 397.2	$ 406.7	$ 217.5
Other comprehensive income (loss), net of tax[(1)]:					
Foreign currency translation adjustment	(161.5)	189.4	434.6	165.2	108.6
Other comprehensive income (loss)	(137.5)	183.4	512.1	90.0	354.0
Comprehensive income (loss)	(82.7)	357.5	964.5	542.8	609.3
Comprehensive income (loss) attributable to non-controlling interest	(3.3)	19.5	52.8	31.6	26.8
Comprehensive income of Emera Incorporated	$ (79.4)	$ 338.0	$ 911.7	$ 511.2	$ 582.5
Adjusted EBITDA[(2)]	$ 319.4	$ 384.2	$ 1,031.2	$ 946.5	$ 829.5
Balance Sheet Data (at period end):					
Assets:					
Current assets:					
Cash and cash equivalents	$ 999.5	$ 305.3	$ 1,073.4	$ 221.1	$ 100.8
Total current assets	2,289.4	1,646.5	2,595.6	1,410.8	1,161.3
Property, plant and equipment, net of accumulated depreciation	6,014.9	5,826.0	6,188.0	5,610.2	5,327.7
Total assets[(3)]	$11,448.6	10,191.7	$11,950.0	$9,853.4	$8,876.8
Short-term debt	$ 10.2	$ 5.7	$ 15.9	$ 257.6	$ 438.0
Current portion of long-term debt	272.6	92.9	274.0	94.5	328.3
Long-term debt[(3)]	3,714.2	3,800.3	3,734.6	3,660.3	3,363.7
Total Emera Incorporated equity	4,091.7	3,691.9	4,200.1	3,398.8	2,608.2
Non-controlling interest in subsidiaries	105.2	321.8	134.0	306.6	289.0
Total equity	4,196.9	4,013.7	4,334.1	3,705.4	2,897.2
Total liabilities and equity[(3)]	$11,448.6	$10,191.7	$11,950.0	$9,853.4	$8,876.8

(1) Certain of these items are net of tax expense or recovery, please refer to Emera's audited consolidated financial statements as at and for the years ended December 31, 2015 and December 31, 2014, which are incorporated by reference herein and Emera's unaudited condensed consolidated interim financial statements as at and for the three months ended March 31, 2016 for more details.

(2) Adjusted EBITDA is a non-U.S. GAAP measure. See "Presentation of Financial Information."

(3) Year ended December 31, 2015 amounts have been adjusted to conform to the accounting presentation applied to amounts for the three months ended March 31, 2016.

TECO Energy Summary Historical Financial Data

The following table shows the summary historical financial data of TECO Energy for the periods and as of the dates indicated. The summary historical financial data presented as of December 31, 2015, 2014 and 2013 and for the year ended December 31, 2015, 2014 and 2013 are derived from the audited financial statements of TECO Energy, which are incorporated by reference in this Prospectus. The summary historical financial data presented as of March 31, 2016 and 2015 and for the three months ended March 31, 2016 and 2015 are derived from the unaudited financial statements of TECO Energy, which are incorporated by reference in this Prospectus.

The following summary historical financial data should be read in conjunction with "Capitalization" contained herein and TECO Energy's financial statements and related notes incorporated by reference in this Prospectus.

	TECO Energy historical				
	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars				
Statement of Operations Data:					
Total revenues[1]	**659.5**	**693.0**	**2,743.5**	**2,566.4**	**2,355.1**
Total expenses	**511.4**	**546.8**	**2,181.4**	**2,061.0**	**1,900.5**
Net income from continuing operations[1]	73.7	63.8	241.2	206.4	188.7
Net income from discontinued operations[1][2]	0.1	(5.8)	(67.7)	(76.0)	9.0
Net income	73.8	58.0	173.5	130.4	197.7
EBITDA[3]	**245.1**	**237.1**	**931.9**	**831.7**	**754.5**
Balance Sheet Data (at period end):					
Total current assets	547.2	728.7	570.3	755.6	857.7
Total property, plant and equipment, net	7,553.0	7,164.7	7,481.8	7,088.2	6,170.1
Total assets	8,981.1	8,777.5	8,933.5	8,726.2	7,448.0
Long-term debt, including current portion	3,573.0	3,627.7	3,822.5	3,628.5	2,921.1
Total capital	2,582.3	2,587.3	2,559.0	2,574.7	2,333.7
Total liabilities and capital	**8,981.1**	**8,777.5**	**8,933.5**	**8,726.2**	**7,448.0**

(1) Years ended December 31, 2015, December 31, 2014 and December 31, 2013 amounts shown include reclassifications to reflect discontinued operations discussed in Note 19 to the TECO Energy Consolidated Financial Statements for the fiscal year ended December 31, 2015.

(2) Three months ended March 31, 2015 amounts have been adjusted to reflect the results from operations to discontinued operations for TECO Coal and certain charges and gains at TECO Energy's Other reportable segment that directly relate to TECO Coal and TECO Guatemala. See Note 15 to TECO Energy's unaudited financial statements for the three months ended March 31, 2016, which are incorporated by reference in this Prospectus.

(3) EBITDA is a non-U.S. GAAP measure. See "Presentation of Financial Information."

Pro Forma Financial Data

The summary unaudited pro forma financial data as of March 31, 2016 and for the fiscal year ended December 31, 2015 and the three months ended March 31, 2016 are derived from Emera's unaudited pro forma consolidated financial statements. The unaudited pro forma consolidated statements of operations for the year ended December 31, 2015 and for the three months ended March 31, 2016 give effect to the Acquisition and related transactions described below as if they had occurred on January 1, 2015. The summary unaudited pro forma consolidated financial information is presented to illustrate the estimated effects of (i) the Acquisition Capital Markets Transactions, (ii) the issuance of Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures) and (iii) the consummation of the Acquisition. The unaudited pro forma consolidated balance sheet information gives effect to the Acquisition Capital Markets Transactions, the issuance of the Common Shares (as described above) and the Acquisition as if they closed on March 31, 2016. The unaudited pro forma consolidated statements of earnings information for the year ended December 31, 2015 and the three months ended March 31, 2016 gives effect to the Acquisition and the Acquisition Capital Markets Transactions as if they had closed on January 1, 2015.

The following summary unaudited pro forma financial data should be read in conjunction with "Caution Regarding Unaudited Consolidated Pro Forma Consolidated Financial Statements," "Capitalization," "Management's Discussion and Analysis," and "Unaudited Pro Forma Consolidated Financial Statements" contained herein and Emera's financial statements and related notes incorporated by reference in this Prospectus. Among other things, the unaudited pro forma financial statements under "Unaudited Pro Forma Consolidated Financial Statements" include more detailed information regarding the basis of presentation for the information in the following table.

	Emera Pro Forma	
	Three months ended March 31	Year ended December 31
	2016	2015
	millions of Canadian dollars	
Statement of Operations Data:		
Total operating revenues	1,784	6,298
Total operating expenses	1,310	5,036
Net Income from continuing operations	243	538
Net income of Emera Incorporated	240	426
Preferred stock dividends	7	30
Net income attributable to common shareholders	233	396
Adjusted EBITDA(1)	$ 657	$2,258
Balance Sheet Data (at period end):		
Current assets:		
Cash and cash equivalents	$ 323	
Total current assets	2,263	
Property, plant and equipment, net of accumulated depreciation	15,812	
Total assets	$27,558	
Short-term debt	$ 676	
Current portion of long-term debt	381	
Long-term debt	14,756	
Total Emera Incorporated equity	6,068	
Non-controlling interest in subsidiaries	105	
Total equity	6,173	
Total liabilities and equity	$27,558	

(1) Adjusted EBITDA is a non-U.S. GAAP measure. See "Presentation of Financial Information."

Pro Forma Non-U.S. GAAP financial measures

EBITDA and Adjusted EBITDA

The following table presents a reconciliation of EBITDA and Adjusted EBITDA to the most directly comparable U.S. GAAP financial measure, on a historical basis and a pro forma basis, for Emera and EBITDA to the most directly comparable U.S. GAAP financial measure, on a historical basis for TECO Energy, for each of the periods indicated. See "Presentation of Financial Information." The Emera pro forma information for the three months ended March 31, 2016 and the year ended December 31, 2015 set forth below has been prepared using the U.S. dollar to Canadian dollar weighted average rates of 1.3748 (for the period January 1, 2016 to March 31, 2016) and 1.2788 (for the period January 1, 2015 to December 31, 2015), respectively.

	Emera Historical		TECO Energy Historical		Emera Pro Forma	
	Three months ended March 31	Year ended December 31	Three months ended March 31	Year ended December 31	Three months ended March 31	Year ended December 31
	2016	2015	2016	2015	2016	2015
	millions of Canadian dollars		*millions of U.S. dollars*		*millions of Canadian dollars*	
Net Income	$ 54.8	$ 452.4	$ 73.7	$241.2	$243.3	$ 537.5
Add:						
Interest expense, net	75.2	212.6	45.9	186.4	192.1	684.1
Income tax expense (recovery)	26.8	92.4	35.7	155.3	74.7	197.2
Depreciation and amortization	87.5	339.9	89.8	349.0	211.0	786.2
EBITDA	$244.3	$1,097.3	$245.1	$931.9	$721.0	$2,205.1
Mark-to-market gain (loss), excluding income tax and interest	(75.1)	66.1			64.4	(52.8)
Adjusted EBITDA	$319.4	$1,031.2			$656.6	$2,257.9

GLOSSARY

In this Prospectus, unless the context otherwise requires:

"**Acquisition**" means the proposed acquisition by Emera of TECO Energy pursuant to the terms of the Acquisition Agreement.

"**Acquisition Agreement**" means the agreement and plan of merger dated September 4, 2015 among Emera, Merger Sub and TECO Energy.

"**Acquisition Capital Markets Transactions**" has the meaning ascribed thereto under the heading "Summary—Financing the Acquisition."

"**Acquisition Credit Agreements**" has the meaning ascribed thereto under the heading "Description of Other Indebtedness—Acquisition Credit Facilities."

"**Acquisition Credit Facilities**" has the meaning ascribed thereto under the heading "Description of Other Indebtedness—Acquisition Credit Facilities."

"**Acquisition-Related Expenses**" means the estimated non-recurring costs, including related income tax effects and any governmental and other imposed costs that may be incurred to consummate the Acquisition. Such costs, which will be fully expensed when incurred in accordance with U.S. GAAP, include but are not limited to fees associated with financial advisory, consulting, accounting, tax, legal and other professional services, bridge facility commitment fees, costs associated with change of control and integration, out-of-pocket costs and other costs of a non-recurring nature.

"**Additional Amounts**" has the meaning ascribed thereto under the heading "Description of the Notes—Payment of Additional Amounts."

"**Adjusted EBITDA**" has the meaning ascribed thereto under the heading "Presentation of Financial Information—Emera EBITDA and Adjusted EBITDA."

"**Adjusted Net Income**" means net income attributable to common shareholders, as defined by U.S. GAAP excluding the effect of after-tax mark-to-market adjustments related to certain derivative instruments, the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp and NWP until NWP's sale on January 29, 2015, the mark-to-market adjustments related to an interest rate swap in EBPC, the mark-to-market adjustments related to the effect of USD-denominated currency and forward contracts put in place to economically hedge the then anticipated proceeds from the Convertible Debenture Offering for the Acquisition and the mark-to-market adjustments included in Emera Energy's margin, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered and the amortization of transportation capacity recognized as a result of certain marketing and trading transactions. See "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures."

"**AFUDC**" means allowance for funds used during construction and represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator.

"**Annual Information Form**" means the annual information form of Emera for the year ended December 31, 2015 dated March 30, 2016.

“**Approval Conditions**” means that (i) the Company has received all regulatory and governmental approvals required to finalize the Acquisition and (ii) the Company and TECO Energy have fulfilled or waived all other outstanding conditions precedent to closing the Acquisition, other than those which by their nature cannot be satisfied until the closing of the Acquisition, in each case as set out in the Acquisition Agreement.

“**APUC**” means Algonquin Power & Utilities Corp.

“**ARO**” means asset retirement obligation.

“**ASU**” means Accounting Standard Update.

“**Atlantic Provinces**” means the region of Canada consisting of the Provinces of New Brunswick, Newfoundland and Labrador, Nova Scotia and Prince Edward Island.

“**Automatic Conversion**” means the automatic conversion of the Notes for newly issued Conversion Preferred Shares upon the occurrence of an Automatic Conversion Event.

“**Automatic Conversion Event**” means an event giving rise to the Automatic Conversion, being the occurrence of any one of the following: (i) the making by Emera of a general assignment for the benefit of its creditors or a proposal (or the filing of a notice of its intention to do so) under the *Bankruptcy and Insolvency Act* (Canada); (ii) any proceeding instituted by Emera seeking to adjudicate it a bankrupt or insolvent or, where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or for any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent; (iii) a receiver, interim receiver, trustee or other similar official is appointed over Emera or for any substantial part of its property and assets by a court of competent jurisdiction in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada; or (iv) any proceeding is instituted against Emera seeking to adjudicate it a bankrupt or insolvent, or where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada, and either such proceeding has not been stayed or dismissed within sixty (60) days of the institution of any such proceeding or the actions sought in such proceedings occur (including the entry of an order for relief against Emera or the appointment of a receiver, interim receiver, trustee, or other similar official for it or for any substantial part of its property and assets).

“**BACT**” means Best Available Control Technology.

“**Bangor Hydro**” means Bangor Hydro Electric Company, a transmission and distribution electric utility company incorporated under the laws of the State of Maine and a wholly owned, indirect subsidiary of Emera which merged on January 1, 2014 with MPS to form Emera Maine.

“**Bangor Hydro District**” means the franchise electric service territory associated with the former Bangor Hydro Electric Company in eastern and Down East Maine.

“**Bayside Power**” means Bayside Power Limited Partnership.

“**Bayside Power Station**” means the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station.

"**BBD**" means Barbadian dollar.

"**Bear Swamp**" means Bear Swamp Power Company, LLC, a 600 MW pumped storage hydroelectric company incorporated under the laws of the State of Delaware in which Emera indirectly holds a 50% interest.

"**BLPC**" means The Barbados Light & Power Company Limited.

"**Board of Directors**" means the board of directors of Emera.

"**Brookfield Renewable Partners**" means Brookfield Renewable Partners L.P.

"**Brooklyn Energy**" means Brooklyn Power Corporation.

"**Brunswick Pipeline**" means the pipeline delivering re-gasified natural gas from the Canaport™ LNG gas terminal near Saint John, New Brunswick to markets in the Northeastern United States, which is owned directly by EBPC.

"**Bull Hill**" means Blue Sky East, LLC, a company incorporated under the laws of the State of Delaware which owns a 34.5 MW wind farm located south of Bangor, Maine, and in which Emera held an indirect interest of 49% through its joint venture with First Wind in NWP until January 29, 2015, when Emera sold its interest in NWP.

"**CAD**" means Canadian dollars.

"**CAIR**" means the U.S. Environmental Protection Agency's Clean Air Interstate Rule, which was replaced by the CSAPR, as of January 1, 2015.

"**Cambrian**" means Cambrian Coal Corp.

"**Canadian Dollar Subordinated Notes**" means the Canadian dollar-denominated unsecured, subordinated notes that may be issued by Emera on a basis that is exempt from the prospectus requirements of applicable Canadian securities laws.

"**Canaport LNG**" means an LNG receiving and regasification terminal in Saint John, New Brunswick. Canaport LNG is a partnership between Repsol S.A. and Irving Oil Limited with Canaport LNG as the developer, owner and operator of the terminal.

"**Cash Offer**" means EBH2's offer to purchase minority shareholders' stakes in ECI for $23.26 ($33.30 Barbadian dollars) in cash per common share.

"**CCRs**" means coal combustion residuals.

"**CFO**" means Chief Financial Officer.

"**Clean Air Act**" means the Clean Air Act, a US federal law related to air pollution, codified at 42 U.S.C. 7401 et seq., as amended.

"**Clean Power Plan**" means the guidelines for existing fossil fuel-fired electric generating units proposed and established by the EPA under the authority of Clean Air Act section 111(d).

"**Clean Water Act**" means the Clean Water Act, a U.S. federal law related to water pollution, codified at 33 U.S.C. 1251 et seq., as amended.

"**Code**" means the U.S. Internal Revenue Code of 1986, as amended.

"**COMFIT**" means the Community Feed-In Tariff, which NSPI is subject to.

"**Common Shares**" means the common shares in the capital of Emera.

"**Companies Act Relief**" has the meaning ascribed thereto under the heading "Business—General Development of the Business—Emera Maine—U.S. GAAP—Exemptive Relief and Companies Act Relief."

"**Conversion Preferred Shares**" means the applicable series of first preferred shares of Emera, as authorized by the Board of Directors, to be issued by Emera upon an Automatic Conversion.

"**Conversion Time**" means the time at which an Automatic Conversion occurs, namely upon an Automatic Conversion Event.

"**Convertible Debenture Make-Whole Payment**" means an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Convertible Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date.

"**Convertible Debenture Offering**" has the meaning ascribed thereto under the heading "Description of Other Indebtedness—Emera—Debentures Represented by Instalment Receipts."

"**Convertible Debentures**" means the 4.0% convertible unsecured subordinated debentures of Emera that were issued on September 28 and October 2, 2015 in order to finance a portion of the Acquisition.

"**CRA**" means Canada Revenue Agency.

"**CRMB**" has the meaning ascribed thereto under the heading "Business—TECO Energy—Capital Expenditures."

"**CSA**" means the various securities commissions or other securities regulatory authorities in the provinces of Canada.

"**CSAPR**" means the U.S. Environmental Protection Agency's Cross-State Air Pollution Rule, a set of rules aimed at reducing power plant emissions that contribute to ozone and fine particle pollution.

"**CT**" means combustion turbine.

"**cybersecurity threats**" has the meaning ascribed thereto under the heading "Management's Discussion and Analysis—Enterprise Risk and Risk Management—Cybersecurity Risk."

"**DC&P**" means disclosure controls and procedures, as such term is defined in "Management's Discussion and Analysis—Disclosure and Internal Controls."

"**Deferral Date**" has the meaning ascribed to thereto under the heading "Description of the Notes—Deferral Right."

"**Deferral Event**" means the election by Emera, at its sole option, to defer the interest payable on the Notes.

"**Deferral Period**" has the meaning ascribed thereto under the heading "Description of the Notes—Deferral Right."

"**Determination of Need**" means a formal process required under Florida law that is conducted by the FPSC. The FPSC reviews the need for the power generated by the proposed facility in relation to the needs of Florida.

"**Dividend Restricted Shares**" has the meaning ascribed thereto under the heading "Description of the Notes—Dividend Stopper Undertaking."

"**Dividend Stopper Undertaking**" has the meaning ascribed thereto under the heading "Description of the Notes—Dividend Stopper Undertaking."

"**Domlec**" means Dominica Electricity Services Limited.

"**DR**" means depositary receipt.

"**DR Offer**" means EBH2's offer to purchase minority shareholders' stakes in ECI for 2.1 DRs per common share.

"**DSM**" means demand side management.

"**DSM Program Costs**" means the requirement of NSPI to purchase electricity efficiency and conservation activities pursuant to legislation of the Government of Nova Scotia.

"**EBITDA**" means earnings before interest, income taxes, depreciation and amortization.

"**EBH2**" means Emera (Barbados) Holdings No. 2 Inc., an indirect wholly owned subsidiary of Emera.

"**EBPC**" means Emera Brunswick Pipeline Company Ltd.

"**ECHL**" means Emera Caribbean Holdings Limited.

"**ECI**" means Emera (Caribbean) Incorporated, effective November 24, 2014, which was formerly Light & Power Holdings Ltd.

"**ECRC**" means an environmental cost recovery clause, which allows for the recovery of costs associated with certain environmental investment and expenses.

"**EE New England Gas Generation**" means Emera Energy Generation II LLC, a company incorporated under the laws of the State of Delaware that holds the New England Gas Generation Facilities and a wholly owned, direct subsidiary of Emera.

"**EES**" means Emera Energy Services.

"**Electricity Plan Act**" means the *Electricity Plan Implementation (2015) Act* (Nova Scotia).

"**ELGs**" means the electric effluent limit guidelines of the EPA.

"**Emera**" means Emera Incorporated.

"**Emera Caribbean**" means BLPC and Domlec (and their parent company, ECI), GBPC, Emera Utility Services (Bahamas) and Lucelec.

“**Emera Common Shares**” means the common shares of Emera.

“**Emera Corporate and Other**” means Emera’s consolidated investment in Emera Utility Services, Emera Reinsurance Limited and Emera’s non-consolidated investments in ENL, NSPML, LIL, APUC and OpenHydro. Corporate and Other also includes other investments and interest revenue on intercompany financings and costs allocated to corporate activities not directly associated with operations, including without limitation, the acquisition costs for the Acquisition and the mark-to-market adjustments related to the effect of USD-denominated currency and forward contracts to economically hedge the anticipated proceeds from the Convertible Debenture Offering for the Acquisition.

“**Emera Energy**” means Emera Energy Incorporated.

“**Emera Energy Generation**” means, collectively, EE New England Gas Generation, Bayside Power and Brooklyn Energy.

“**Emera Energy Services**” means Emera Energy Services, Inc., a natural gas and electricity marketing and trading company incorporated under the laws of the State of Delaware and a wholly owned, indirect subsidiary of Emera Energy.

“**Emera Maine**” means the company resulting from the merger of Bangor Hydro Electric Company and Maine Public Service Company under the laws of the state of Maine on January 1, 2014, and a wholly-owned indirect subsidiary of Emera.

“**Emera Preferred Shares**” means the preferred shares of Emera (including the Conversion Preferred Shares).

“**Emera US Finance**” means Emera US Finance LP

“**Emera Utility Services**” means Emera Utility Services Inc.

“**ENL**” means Emera Newfoundland and Labrador Holdings, Incorporated.

“**EPA**” means the United States Environmental Protection Agency.

“**Equity Credit Methodology**” means the methodology or criteria employed by Moody’s or S&P for purposes of assigning equity credit to securities such as the Notes that was effective on the date of the original issuance of a series of Notes.

“**EUS Bahamas**” means Emera Utility Services (Bahamas) Limited.

“**EUSHI**” means Emera US Holdings Inc., a wholly-owned (directly and indirectly) subsidiary of the Company.

“**Exchange Act**” means the Securities Exchange Act of 1934, as amended.

“**Exemptive Relief**” has the meaning ascribed thereto under the heading “Business—General Development of the Business—Emera Maine—U.S. GAAP—Exemptive Relief and Companies Act Relief.”

“**Extraordinary Resolution**” means (i) the written consent of holders of not less than a majority of the aggregate principal amount of the Notes or an applicable series of Notes; or (ii) an extraordinary resolution proposed at a meeting of holders of the Notes where holders of not less than a majority of the aggregate principal amount of the Notes, or of each applicable series of Notes if a serial meeting, are represented in person or by proxy (or a lesser amount of holders if such meeting has been dissolved and reconvened due to failure to achieve quorum in the manner specified in the Trust Indenture) and passed by the favourable votes of holders of the Notes representing not less than 66⅔% of the aggregate principal amount of the Notes represented at the meeting.

“**FAM**” means the fuel adjustment mechanism established by the UARB.

“**FASB**” means the Financial Accounting Standards Board.

"**FCA**" means, with respect to Emera Energy Generation, forward capacity auction.

"**FDEP**" means Florida Department of Environmental Protection.

"**FERC**" means the United States Federal Energy Regulatory Commission.

"**FGD**" means flue gas desulfurization.

"**Final Instalment**" means the remaining Cdn$667 per Cdn$1,000 principal amount of Convertible Debentures that is payable on the Final Instalment Date.

"**Final Instalment Date**" has the meaning ascribed thereto under the heading "Management's Discussion and Analysis—Developments—Emera—Convertible Debentures Represented By Instalment Receipts."

"**First Preferred Shares**" means the first preferred shares in the capital of Emera.

"**First Wind**" means First Wind Holdings LLC, a company incorporated under the laws of the State of Delaware.

"**FLG**" has the meaning ascribed thereto under the heading "Business—General Development of the Business—Maritime Link Project and Strategic Partnership with Nalcor on Muskrat Falls Projects."

"**FLG Completion Guarantee**" means a completion guarantee granted by Emera in favour of the Government of Canada under which 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 FLG Completion Guarantee. The FLG Payment Obligation Agreement (as defined below) and FLG Completion Guarantee collectively satisfy the requirement in the FLG term sheet to deliver the condition precedent in the FLG term sheet to deliver to the Government of Canada a guarantee of certain payment and performance obligations, which condition precedent was satisfied collectively by the FLG Completion Guarantee (as defined above) and the FLG Payment Obligation Agreement (as defined below).

"**FLG Payment Obligation Agreement**" means a payment obligation agreement between Emera, NSPML and the Government of Canada, which together with the FLG Completion Guarantee (as defined above) collectively satisfy the requirement in the FLG term sheet to deliver a guarantee agreement from Emera.

"**FPSC**" means the Florida Public Service Commission.

"**Fuel Costs**" means certain fuel-related costs as described in "Management's Discussion and Analysis—NSPI—Overview."

"**Fuel Electric Revenues**" means NSPI's electric revenues related to the recovery of Fuel Costs.

"**Gas Industry Standards Board**" means the Gas Industry Standards Board, the precursor to the NAESB.

"**GBPA**" means The Grand Bahama Port Authority.

"**GBPC**" means The Grand Bahama Power Company Limited.

"**GCBF**" means gas cost billing factor.

"**GDP**" means gross domestic product.

"**GHG**" means greenhouse gas.

"**GRA**" means general rate application.

“**Guarantors**” has the meaning ascribed thereto under the heading “Description of Other Indebtedness—Proposed Emera US Finance Senior Guaranteed Notes.”

“**GWh**” means the amount of electricity measured in gigawatt hours.

“**HAPS**” has the meaning ascribed thereto under the heading “Business—TECO Energy.”

“**HFT**” means held-for-trading.

“**Hydro-Québec**” means Hydro-Québec, the public utility.

“**ICDU**” means ICD Utilities Limited.

“**ICFR**” means internal controls over financial reporting.

“**ICSID**” means the International Centre for the Settlement of Investment Disputes.

“**IFRS**” means International Financial Reporting Standards.

“**IGCC**” means integrated gasification combined-cycle.

“**Indenture Trustee**” means CST Trust Company and American Stock Transfer & Trust Company, LLC, or such other successor trustee or trustees as may be appointed from time to time pursuant to the Trust Indenture.

“**Ineligible Person**” means any person whose address is in, or whom Emera or its transfer agent has reason to believe is a resident of, any jurisdiction outside of Canada and the U.S. to the extent that: (i) the issuance or delivery by Emera to such person, upon an Automatic Conversion of Conversion Preferred Shares, would require Emera to take any action to comply with securities or analogous laws of such jurisdiction; or (ii) withholding tax would be applicable in connection with the delivery to such person of Conversion Preferred Shares upon an Automatic Conversion.

“**instalment receipts**” means the instalment receipts representing beneficial ownership of the Convertible Debentures.

“**IOU** ” means Investor Owned Utility.

“**IPP**” means independent power producer.

“**IRCD**” means the Independent Regulatory Commission, Dominica.

“**ISO-NE**” means the independent, non-profit regional transmission organization that oversees the operation of New England’s bulk electric power system and transmission lines, generated and transmitted by its member utilities.

“**km**” means kilometre.

“**Labrador-Island Transmission Link Project**” means an electricity transmission project in Newfoundland and Labrador being developed by Nalcor, which will enable the transmission of the Muskrat Falls energy between Labrador and the island of Newfoundland.

“**Labrador Transmission Assets**” means an electricity transmission project in Labrador between Muskrat Falls and Churchill Falls.

“**LIBOR**” means, for any interest period in respect of a series of Notes, the rate for U.S. dollar borrowings appearing on page LIBOR01 of the Reuters Service (or on any successor or substitute page of such Service, or any successor to or substitute for such Service providing rate quotations comparable to those currently provided on such page of such Service, as determined by the Company from time to time for purposes of providing quotations of interest rates applicable to U.S. dollar deposits in the London interbank market) at approximately 11:00 a.m., London, time, two business days prior to the commencement of such interest period, as the rate for U.S. dollar deposits with a maturity comparable to such interest period. In the event that such rate is not available at such time for any reason, the "**LIBOR**" for such interest period shall be the rate at which U.S. dollar deposits of U.S.$5,000,000 and for a maturity comparable to such interest period are offered by the principal London offer of an agent selected by Emera in immediately available funds in the London interbank market at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such interest period.

"**LIL**" means Labrador Island Link Limited Partnership.

"**LNG**" means liquefied natural gas.

"**LPH**" means Light & Power Holdings Ltd., the former name of ECI.

"**Lucelec**" means St. Lucia Electricity Services Limited.

"**M&NP**" means the Maritimes & Northeast Pipeline Limited Partnership and Maritimes and Northeast Pipeline LLC.

"**MACT**" has the meaning ascribed thereto under the heading "Business—TECO Energy."

"**Maine & Maritimes Corporation**" means Maine & Maritimes Corporation, a company incorporated under the laws of the State of Maine, the parent company of MPS, and a wholly owned, indirect subsidiary of Emera; Maine & Maritimes Corporation was dissolved when MPS and Bangor Hydro merged on January 1, 2014, forming Emera Maine..

"**MAP 21**" means the Moving Ahead for Progress in the 21st Century Act.

"**Maritime Link Act**" means the *Maritime Link Act* (Nova Scotia).

"**Maritime Link Joint Development Agreement**" means the agreement dated July 31, 2014 between Nalcor and Emera relating to the development of the Maritime Link Project.

"**Maritime Link Project**" means the transmission project including two 170 km sub-sea cables between the island of Newfoundland and Nova Scotia, being developed by NSPML

"**Maritime Provinces**" means the region of Canada consisting of the Provinces of Nova Scotia, New Brunswick, and Prince Edward Island.

"**MATS**" means the U.S. Environmental Protection Agency's Mercury Air Toxics Standards, a rule issued pursuant to section 112 of the Clean Air Act aimed at reducing mercury, acid gases and other toxic pollution from power plants.

"**MD&A**" means Emera's Management's Discussion and Analysis for the three months ended March 31, 2016 and the fiscal year ended December 31, 2015, incorporated herein by reference copies of which is available electronically under Emera's profile on SEDAR at www.sedar.com.

"**Merger Sub**" means Emera US Inc., a direct wholly-owned subsidiary of EUSHI.

"**MLFT**" means Maritime Link Financing Trust, a special purpose funding vehicle formed by Emera.

"**MMBTU**" means one million British thermal units.

"**Moody's**" means Moody's Investor Service, Inc.

"**MOU**" has the meaning ascribed thereto under the heading "Risk Factors—Risk Factors Relating to the Acquisition."

"**MPS**" means Maine Public Service Company, which merged with Bangor Hydro Electric Company to become Emera Maine.

"**MPS District**" means the franchise electric service territory associated with the former Maine Public Service Company in northern Maine.

"**MPUC**" means the Maine Public Utilities Commission.

"**MREI**" means the Maine Renewable Energy Interconnect project proposed by Central Maine Power Company and Emera Maine.

"**MTM**" means mark-to-market.

"**MTN**" means medium-term notes.

"**Muskrat Falls Generating Station**" means a hydroelectric generating facility at Muskrat Falls being developed by Nalcor on the Lower Churchill River in Labrador.

"**Muskrat Falls Hydroelectric Project**" means, collectively, the Muskrat Falls Generating Station, the Labrador Transmission Assets, and the Labrador-Island Transmission Link Project.

"**MW**" means megawatts.

"**MWh**" means megawatt-hours.

"**NAESB**" means the North American Energy Standards Board.

"**Nalcor**" means Nalcor Energy, a Newfoundland and Labrador provincial Crown corporation.

"**NB Powe**r" means New Brunswick Power Corporation.

"**NEB**" means the Canadian National Energy Board.

"**New England Gas Generation Facilities**" means a three-facility, 1,090 MW combined-cycle gas-fired electricity -generating investment in the Northeastern United States, comprising Bridgeport Energy (560 MW) in Bridgeport, -Connecticut; Tiverton Power (265 MW) in Tiverton, Rhode Island; and Rumford Power (265 MW) in Rumford, Maine.

"**NLPUB**" means the Newfoundland and Labrador Board of Commissioners of Public Utilities.

"**NMGC**" means New Mexico Gas Company, Inc.

"**NMGI**" means New Mexico Gas Intermediate, Inc.

"**NMPRC**" means the New Mexico Public Regulation Commission.

"**No.**" means number.

"**Non-Fuel Electric Revenues**" means NSPI's revenues related to the recovery of non-fuel costs.

"**Non-Resident Holder**" means a holder of Notes who acquires Notes and who, for purposes of the Tax Act and at all relevant times, is not, and is not deemed to be, resident in Canada, deals at arm's length with and is not affiliated with Emera or any of its affiliates and holds Notes and any Conversion Preferred Shares as capital property.

"**NPNS**" means normal purchases and normal sales.

"**NSPC**" means Nova Scotia Power Corporation.

"**NSPFC**" means Nova Scotia Power Finance Corporation.

"**NSPI**" means Nova Scotia Power Incorporated.

"**NSPML**" means NSP Maritime Link Incorporated.

"**NWP**" means Northeast Wind Partners II, LLC.

"**NYSE**" means the New York Stock Exchange.

"**OATT**" means open access transmission tariff.

"**OM&G**" means operating, maintenance and general, with respect to costs.

"**Participants**" means the participants in the depository service of the Clearing Agency.

"**PBO**" means the net actuarial gain or loss, which exceeds 10% of the greater of the projected benefit obligation/accumulated post-retirement benefit obligation, as defined in "Management's Discussion and Analysis—Pension and Other Post-Retirement Employee Benefits."

"**Perpetual Preferred Share Rate**" has the meaning ascribed thereto under the heading "Description of Conversion Preferred Shares—Dividends."

"**petcoke**" means petroleum coke.

"**PGA**" means purchased gas adjustment.

"**PGAC**" means purchased gas adjustment clause.

"**PGS**" means Peoples Gas System, the gas division of Tampa Electric Company.

"**PHMSA**" has the meaning ascribed thereto under the heading "Risk Factors—Risk Factors Relating to the Acquisition."

"**Polk Power Station**" means Tampa Electric's integrated coal gasification combined-cycle power plant, located on State Road 37 in Polk County, Florida.

"**PPA**" means power purchase agreement.

"**PPSA**" means the Florida's Power Plant Siting Act.

"**PSC**" means the Florida Public Service Commission.

"**Prospectus**" means this prospectus.

"**Prospectus Supplement**" has the meaning ascribed thereto on the cover page of this Prospectus.

“**PRP**” means potentially responsible party.

“**Public Utilities Act**” means the *Public Utilities Act* (Nova Scotia).

A “**Rating Event**” means the amount of equity credit assigned to a series of Notes by Moody’s or S&P has been reduced due to an amendment to, clarification or change in, the Equity Credit Methodology.

“**RECL**” means Repsol Energy Canada Ltd.

“**regulated net income**” means net income from regulated subsidiaries.

“**Revolving Facility**” has the meaning ascribed thereto under the heading “Description of Other Indebtedness—Revolving Facility.”

“**RFP**” means request for proposal.

“**ROE**” means return on equity.

“**S&P**” means Standard & Poor’s Ratings Services.

“**Sable Wind Project**” means a 13.8 MW wind farm near Canso, Nova Scotia.

“**SCR**” means selective catalytic reduction.

“**SEC**” means the U.S. Securities and Exchange Commission.

“**Securities Act**” means the United States Securities Act of 1933, as amended.

“**SEDAR**” means the System for Electronic Document Analysis and Retrieval.

“**Selling Debentureholder**” means Emera Holdings NS Company, a direct wholly-owned subsidiary of Emera.

“**Senior Guaranteed Note Indenture**” has the meaning ascribed thereto under the heading “Description of the Indebtedness—Proposed Emera US Finance Senior Guaranteed Notes.”

“**Senior Guaranteed Notes**” has the meaning ascribed thereto under the heading “Summary—Financing the Acquisition.”

“**Senior Indebtedness**” means obligations (other than non-recourse obligations, Notes issued under the Trust Indenture or any other obligations specifically designated as being subordinate in right of payment to Senior Indebtedness) of, or guaranteed or assumed by, Emera for borrowed money or evidenced by bonds, debentures or notes or obligations of Emera for or in respect of bankers’ acceptances (including the face amount thereof), letters of credit and letters of guarantee (including all reimbursement obligations in respect of each of the forgoing) or other similar instruments, and amendments, renewals, extensions, modifications and refunding of any such indebtedness or obligation.

“**Senior Notes**” has the meaning ascribed thereto under the heading “Summary—Financing the Acquisition.”

“**Series A First Preferred Shares**” means the cumulative 5-year rate reset first preferred shares, Series A of Emera.

"**Series B First Preferred Shares**" means the cumulative floating rate first preferred shares, Series B of Emera.

"**Series C First Preferred Shares**" means the cumulative rate reset first preferred shares, Series C of Emera.

"**Series E First Preferred Shares**" means the cumulative redeemable first preferred shares, Series E of Emera.

"**Series F First Preferred Shares**" means the cumulative redeemable rate reset first preferred shares, Series F of Emera.

"**SIA**" means the Strategic Investment Agreement dated April 29, 2011 between Emera and APUC.

"**SO_2**" means sulfur dioxide.

"**South Canoe Wind Project**" means a wind farm project approved by the Municipality of the District of Chester on March 14, 2013.

"**Special Mandatory Redemption Date**" means the 20th Business Day following the earlier of the Special Mandatory Redemption Triggering Date and the date on which the Acquisition Agreement is terminated.

"**Special Mandatory Redemption Triggering Date**" has the meaning ascribed thereto under the heading "Description of Other Indebtedness—Proposed Emera US Finance Senior Guaranteed Notes."

"**SunEdison**" means SunEdison, Inc.

"**Superfund**" means a fund established to finance a long-term, permanent remedial project in connection with the U.S. federal government's program to clean up the uncontrolled hazardous waste sites in the United States.

"**Tampa Electric**" means Tampa Electric, the electric division of TEC.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**Tax Event**" means Emera has received an opinion of independent counsel of a nationally recognized law firm in Canada or the U.S. experienced in such matters (who may be counsel to Emera) to the effect that, as a result of, (i) any amendment to, clarification of, or change (including any announced prospective change) in, the laws, or any regulations thereunder, or any application or interpretation thereof, of Canada or the U.S. or any political subdivision or taxing authority thereof or therein, affecting taxation; (ii) any judicial decision, administrative pronouncement, published or private ruling, regulatory procedure, rule, notice, announcement, assessment or reassessment (including any notice or announcement of intent to adopt or issue such decision, pronouncement, ruling, procedure, rule, notice, announcement, assessment or reassessment) (collectively, an "administrative action"); or (iii) any amendment to, clarification of, or change in, the official position with respect to or the interpretation of any administrative action or any interpretation or pronouncement that provides for a position with respect to such administrative action that differs from the theretofore generally accepted position, in each of case (i), (ii) or (iii), by any legislative body, court, governmental authority or agency, regulatory body or taxing authority, irrespective of the manner in which such amendment, clarification, change, administrative action, interpretation or pronouncement is made known, which amendment, clarification, change or administrative action is effective or which interpretation, pronouncement or administrative action is announced on or after the date of issue of the Notes, there is more than an insubstantial risk (assuming any proposed or announced amendment, clarification, change, interpretation, pronouncement or administrative action is effective and applicable) that Emera is, or may be, subject to more than a de minimis amount of additional taxes, duties or other governmental charges or civil liabilities because the treatment of any of its items of income, taxable income, expense, taxable capital or taxable paid-up capital with respect to the Notes (including the treatment by Emera of interest on any series of Notes), as or as would be reflected in any tax return or form filed, to be filed, or otherwise could have been filed, will not be respected by a taxing authority.

"**Tax Proposals**" means all specific proposals to amend the Tax Act and the regulations thereunder publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date of this Prospectus.

"**TDI New England**" means Champlain VT, LLC doing business as "TDI New England."

"**TEC**" means Tampa Electric Company, the principal subsidiary of TECO Energy, Inc.

"**TECO Coal**" means TECO Coal LLC, and its subsidiaries, a coal producing subsidiary of TECO Diversified.

"**TECO Coal SPA**" means the Securities Purchase Agreement for the sale of TECO Coal to Cambrian.

"**TECO Diversified**" means TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation.

"**TECO Energy**" means the holding company, TECO Energy, Inc. and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries.

"**TECO Finance**" means TECO Finance, Inc., a financing subsidiary for the unregulated businesses of TECO Energy, Inc.

"**TECO Guatemala**" means TECO Guatemala, Inc., a subsidiary of TECO Energy, Inc., parent company of formerly owned generating and transmission assets in Guatemala.

"**TGH**" means TECO Guatemala Holdings, LLC.

"**therm**" equals 100,000 British thermal units, or 0.10 MMBTU.

"**Trust Indenture**" means the trust indenture to be entered into between Emera and American Stock Transfer & Trust Company, LLC and CST Trust Company, as Indenture Trustee, providing for the issuance of Notes by Emera, as amended, restated or supplemented from time to time.

"**TSX**" means the Toronto Stock Exchange.

"**U.S.**" means the United States of America.

"**U.S. dollars**" or "**USD**" or "**U.S.$**" means the lawful currency of the U.S.

"**U.S. GAAP**" means Generally Accepted Accounting Principles in the United States.

"**U.S. person**" has the meaning set out under the Securities Act.

"**UARB**" means the Nova Scotia Utility and Review Board.

"**VaR**" means value-at-risk.

"**WOTUS**" has the meaning ascribed thereto under the heading "Business—TECO Energy—EPA Waters of the U.S."

RISK FACTORS

An investment in the Notes involves certain risks. A prospective purchaser of the Notes should carefully consider the risk factors described under:

(a) the heading "Principal Risks and Uncertainties" in note 32 to Emera's audited consolidated financial statements as at and for the years ended December 31, 2015 and 2014, as found on pages 165 to 166 of the Company's 2015 Annual Report; and

(b) the heading "Principal Risks and Uncertainties" in note 24 to Emera's unaudited interim financial statements as at and for the three months ended March 31, 2016, as found on pages 40 to 42 of such statements,

each of which is incorporated by reference herein. In addition, a prospective purchaser of the Notes should carefully consider the risk factors described in this section which relate to the Acquisition, the Notes and the post-Acquisition business and operations of the Company and TECO Energy, as well as the other information contained in this Prospectus (including the documents incorporated by reference herein).

Risk Factors Relating to the Acquisition

Failure to complete the Acquisition

The closing of the Acquisition is subject to the normal commercial risks that the Acquisition will not close on the terms negotiated or at all. The completion of the Acquisition is subject to satisfaction of the Approval Conditions, including obtaining the approval of NMPRC, which is pending, and the satisfaction or waiver of certain closing conditions contained in the Acquisition Agreement, including the absence of any law or judgement that prevents, makes illegal or prohibits the consummation of the Acquisition. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Acquisition Agreement may result in the termination of the Acquisition Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Emera will complete the Acquisition in the timeframe or on the basis described herein, if at all. Furthermore, Emera or TECO Energy may terminate the Acquisition Agreement if (i) the closing of the Acquisition has not occurred by September 30, 2016 (subject to a six-month extension if required to obtain necessary regulatory approvals) or (ii) a law or judgement preventing or prohibiting the closing of the Acquisition has become final. The termination of the Acquisition Agreement may have a negative effect on the price of the Notes. If the closing of the Acquisition does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence. See "The Acquisition Agreement."

Length of time required to complete the Acquisition is unknown

As described above under "—Failure to complete the Acquisition," the closing of the Acquisition remains subject to the receipt of NMPRC approval and the satisfaction or waiver of certain closing conditions contained in the Acquisition Agreement. There is no certainty, nor can Emera provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining the NMPRC approval or the imposition of unfavourable terms and/or conditions could have a material adverse effect on the Company's ability to complete the Acquisition and on the Company's or TECO Energy's business, financial condition or results of operations. In addition, in the event that regulatory agencies imposed unfavorable terms and/or conditions on Emera or any TECO Energy utility (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Company would still be required to complete the transaction on the terms set forth in the Acquisition Agreement. Emera intends to complete the Acquisition within fifteen business days of obtaining the required regulatory approvals and satisfying the other required closing conditions. See "The Acquisition Agreement."

Emera may not realize all of the anticipated benefits of the Acquisition

Emera believes that the Acquisition will provide benefits to the Company, including that the Acquisition will be accretive to Emera's earnings and will provide significant accretion to Emera's cash position. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Company. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Company. The challenge of combining previously independent businesses makes evaluating the Company's business and future financial prospects difficult. The past financial performance of the Company may not be indicative of its future financial performance. In addition, regulatory approvals required in connection with the Acquisition may include terms which could have an adverse effect on the Company's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the Acquisition may impact the financial performance of the Company. See "—Risk Factors Relating to the Post-Acquisition Business and Operations of Emera and TECO Energy."

Foreign exchange risk

The cash consideration for the Acquisition is required to be paid in U.S. dollars, while a portion of the funds raised in certain of the Acquisition Capital Markets Transactions and the balance of the payments due upon the Final Instalment of the Convertible Debentures will be denominated in Canadian dollars. In addition, any cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) that Emera holds that will be used to fund the Acquisition may be held in Canadian dollars. See "Use of Proceeds." As a result, increases in the value of the U.S. dollar versus the Canadian dollar will increase the purchase price translated in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Acquisition.

Emera may enter into hedge arrangements for the remaining portion of Canadian dollar financing, if any. The failure to enter into hedging arrangements could result in adverse impacts greater than if hedging had been used.

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

Significant demands will be placed on Emera as a result of the Acquisition

As a result of the pursuit and completion of the Acquisition, significant demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Alternate sources of funding that would be used to fund the Acquisition or replace the Acquisition Credit Facilities may not be available

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) the proceeds from the Acquisition Capital Markets Transactions, (ii) the receipt of payment in full on the Final Instalment Date of the Final Instalment due under the Convertible Debentures, (iii) amounts drawn under the Acquisition Credit Facilities, if any, and (iv) existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) and other sources available to the Company.

In connection with financing the Acquisition, in addition to the offering by Emera of any series of Notes pursuant to one or more Prospectus Supplements, Emera US Finance intends to issue Senior Guaranteed Notes. In addition, Emera intends to issue one or more series of Canadian dollar-denominated unsecured senior notes and may also issue Canadian dollar-denominated unsecured subordinated notes, in each case, on a basis which is exempt from the prospectus requirements of applicable Canadian securities laws.

Emera intends to raise up to approximately Cdn$6.6 billion in aggregate principal amount in the Acquisition Capital Markets Transactions. The aggregate principal amounts raised in the Acquisition Capital Markets Transactions and the terms on which such securities are issued are dependent on market and other conditions and may vary. See "Summary—Financing the Acquisition" for more information. The offering of any series of Notes hereunder is not contingent upon the consummation of the Acquisition or the other Acquisition Capital Markets Transactions. There can be no guarantee that the offerings of the securities to be issued in the Acquisition Capital Markets Transactions may be consummated at the desired time or at all, or on cost-efficient terms. In addition, to the extent (i) Emera raises less than Cdn$6.6 billion in connection with the Acquisition Capital Markets Transactions, or (ii) Emera does not receive payment in full of the Final Instalment of the Convertible Debentures, Emera intends to pay any shortfall by drawing on the Acquisition Credit Facilities and/or using existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) or other sources available to Emera in order to consummate the Acquisition. The interest rates and other fees that will be payable by Emera on amounts drawn under the Acquisition Credit Facilities may be more than those expected to be paid on the securities to be issued in the Acquisition Capital Markets Transactions. The terms of the Acquisition Credit Facilities may also be more restrictive than those that Emera expects to be subject to pursuant to the various agreements governing the Acquisition Capital Markets Transactions. Such amounts drawn under the Acquisition Credit Facilities will also be required to be paid within one year, pursuant to the terms of such facilities.

The inability to obtain alternate sources of funding, on attractive terms or at all, to fund the Acquisition or replace the Acquisition Credit Facilities may negatively impact the financial performance of Emera, including the extent to which the Acquisition is accretive. In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the Acquisition.

Emera may not receive payment in full of the Final Instalment of the Convertible Debentures

The offering of any series of Notes as contemplated hereunder is not contingent upon payment in full of the Final Instalment of the Convertible Debentures. If a material amount due on payment of the Final Instalment is not paid by holders of Convertible Debentures represented by instalment receipts and Emera is not able to quickly realize on the Convertible Debentures pledged to secure the obligation to pay the Final Instalment, Emera will not be able to use those proceeds to finance, directly or indirectly, part of the purchase price payable for the Acquisition (including Acquisition-Related Expenses) and to reduce amounts outstanding under the Acquisition Credit Facilities, to the extent any amounts are drawn on such facilities in connection with the Acquisition. As a result, Emera may need to draw amounts under the Acquisition Credit Facilities to cover any shortfall, which will increase Emera's debt service costs and negatively impact the financial performance of Emera until such time as the Acquisition Credit Facilities have been repaid by Emera in full.

Emera does not currently control TECO Energy and its subsidiaries

Although the Acquisition Agreement contains covenants on the part of TECO Energy regarding the operation of its business prior to closing the Acquisition, Emera will not control TECO Energy and its subsidiaries until completion of the Acquisition and the TECO Energy business and results of operations may be adversely affected by events that are outside of the Company's control during the intervening period. Historic and current performance of TECO Energy's business and operations may not be indicative of success in future periods. The future performance of TECO Energy may be influenced by, among other factors, economic downturns, existing and future environmental laws and regulations, turmoil in financial markets, unfavourable regulatory decisions, rising interest rates and other factors beyond the Company's control. As a result of any one or more of these factors, among others, the operations and financial performance of TECO Energy may be negatively affected which may adversely affect the future financial results of Emera. See "—Risk Factors Relating to the Post-Acquisition Business and Operations of Emera and TECO Energy."

Emera expects to incur significant Acquisition-Related Expenses

Emera expects the Acquisition-Related Expenses to be significant. The substantial majority of these costs will be non-recurring expenses resulting from the Acquisition and will consist of transaction costs related to the Acquisition, including costs relating to the financing of the Acquisition and obtaining regulatory approval. Acquisition-Related Expenses may exceed the amounts anticipated by Emera and additional unanticipated costs may be incurred.

TECO Energy and its subsidiaries are subject to business uncertainties and contractual restrictions while the Acquisition is pending that could adversely affect TECO Energy's financial results

Uncertainty about the effect of the Acquisition on employees or vendors and others, including contractors, may have an adverse effect on TECO Energy. Although TECO Energy intends to take steps designed to reduce any adverse effects, these uncertainties may impair TECO Energy's and its subsidiaries' ability to attract, retain and motivate key personnel until the Acquisition is completed, and could cause vendors and others, including contractors, that deal with TECO Energy to seek to change existing business relationships. Employee retention and recruitment may be particularly challenging prior to the completion of the Acquisition, as current employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite TECO Energy's retention and recruiting efforts, key employees depart or fail to accept employment with TECO Energy or its subsidiaries due to the uncertainty of employment and difficulty of integration or a desire not to remain with the combined company, following completion of the Acquisition. TECO Energy may incur significant costs in identifying, hiring, and retaining replacements for departing employees, which could have a material adverse effect on TECO Energy's business operations and financial results. TECO Energy expects that matters relating to the Acquisition and integration-related issues will place a significant burden on management, employees and internal resources, which could otherwise have been devoted to other business opportunities. The diversion of management time on Acquisition-related issues could affect TECO Energy's financial results.

In addition, the Acquisition Agreement restricts TECO Energy and its subsidiaries from taking specified actions until the Acquisition occurs or the Acquisition Agreement is terminated, without Emera's prior written consent, including, without limitation: (i) making certain material acquisitions and dispositions of assets or businesses; (ii) making any capital expenditures in excess of specified amounts; (iii) incurring indebtedness, subject to certain exceptions; (iv) issuing equity or equity equivalents; and (v) paying quarterly cash dividends in excess of levels agreed upon in the Acquisition Agreement. These restrictions may prevent TECO Energy from pursuing otherwise attractive business opportunities and making other changes to its business prior to consummation of the Acquisition or termination of the Acquisition Agreement.

TECO Energy and Emera have been and may continue to be the target of securities class action suits and derivative suits which could result in substantial costs and divert management attention and resources

Securities class action suits and derivative suits are often brought against companies who have entered into mergers and acquisition transactions. Following the announcement of the execution of the Acquisition Agreement, 12 putative stockholder class actions were filed challenging the Acquisition. In November 2015, the defendants party to the litigation entered into a Memorandum of Understanding (the "MOU") with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Acquisition. As a result of the MOU, TECO Energy made additional disclosures related to the proposed Acquisition in a proxy supplement filed on November 18, 2015. The MOU provides for the parties to enter into a formal settlement agreement which will be submitted to the Hillsborough Circuit Court Judge for approval after completion of the Acquisition. Additionally the judge will consider the award of attorneys' fees to the plaintiffs' lawyers. Defending against these claims, even if meritless, can result in substantial costs to TECO Energy and Emera and could divert the attention of its management.

Risk Factors Relating to the Post-Acquisition Business and Operations of Emera and TECO Energy

For additional risk factors relating to Emera, see "Management's Discussion and Analysis—Enterprise Risk and Risk Management."

Emera will have a substantial amount of indebtedness which may adversely affect its cash flow and ability to operate its business

After giving effect to the Acquisition, Emera will have a significant amount of debt, including U.S.$4.1 billion of debt of TECO Energy assumed by Emera as a result of the Acquisition. As of March 31, 2016, on a pro forma basis after giving effect to the Acquisition and the Acquisition Capital Markets Transactions, but assuming conversion of all Convertible Debentures to Common Shares, details of which are included in the capitalization table provided herein, Emera would have approximately Cdn$15.5 billion of total indebtedness outstanding. See "Capitalization."

An offering of Notes could result in a downgrade of Emera's credit ratings

The change in the capital structure of Emera as a result of the Acquisition, any series of Notes offered hereunder and the other Acquisition Capital Markets Transactions could cause credit rating agencies which rate the outstanding debt obligations of Emera to re-evaluate and potentially downgrade the current credit ratings, which could increase the Company's borrowing costs.

Emera's historical and pro forma combined financial information may not be representative of the results of Emera following the Acquisition

The pro forma combined financial information included in this Prospectus has been prepared using the consolidated historical financial statements of Emera and the consolidated historical financial statements of TECO Energy and does not purport to be indicative of the financial information that will result from the operations of Emera on a consolidated basis following the Acquisition. In addition, the pro forma combined financial information included in this Prospectus is based in part on certain assumptions regarding the Acquisition that Emera currently believes are reasonable. Emera makes no assurances that its current assumptions will prove to be accurate over time. Accordingly, the historical and pro forma financial information included in this Prospectus does not necessarily represent the results of operations and financial condition had Emera and TECO Energy operated as a combined entity during the periods presented, or of the results of operations and financial condition in the future. The potential for future business success and operating profitability must be considered in light of the risks, uncertainties, expenses and difficulties typically encountered by recently combined companies. The pro forma combined financial information included in this Prospectus has not been prepared in compliance with Regulation S-X.

In preparing the pro forma financial information contained in this Prospectus, Emera has given effect to (i) the Acquisition Capital Markets Transactions; (ii) the issuance of the Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures); and (iii) the consummation of the Acquisition. While Emera's management believes that the estimates and assumptions underlying the pro forma financial information are reasonable, such assumptions and estimates may be materially different than Emera's actual experience following completion of the Acquisition. See also "—Risk Factors Relating to the Acquisition," "Presentation of Financial Information" and "Unaudited Pro Forma Consolidated Financial Statements—Notes to Unaudited Pro Forma Consolidated Financial Statements."

In particular, we may not be able to consummate the other offerings of securities forming part of the Acquisition Capital Markets Transactions, either at the desired times or at all, or on cost-effective terms. Any differences in the amounts or terms of the Acquisition Capital Markets Transactions to those set forth in this Prospectus may increase our anticipated debt service costs or reduce our anticipated liquidity as shown in the pro forma financial statements and may have a material adverse effect on the Company's business, financial condition or future prospects. Among other things, if we are not able to raise Cdn$6.6 billion in aggregate proceeds from the Acquisition Capital Markets Transactions, Emera may be required to draw down amounts, under the Acquisition Credit Facilities, which may also increase Emera's anticipated debt service costs.

Potential undisclosed liabilities associated with the Acquisition

In connection with the Acquisition, there may be liabilities of TECO Energy and its subsidiaries that the Company failed to discover or was unable to quantify in the due diligence which it conducted prior to the execution of the Acquisition Agreement. The discovery or quantification of any material liabilities of TECO Energy and its subsidiaries could have a material adverse effect on the Company's business, financial condition or future prospects.

Emera may be unable to successfully combine the businesses of Emera and TECO Energy to realize the anticipated benefits of the Acquisition

The combination of the businesses of Emera and TECO Energy will require the dedication of substantial effort, time and resources on the part of management which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurance that management will be able to combine the operations of each of the businesses successfully or achieve any of the benefits that are anticipated as a result of the Acquisition. The extent to which the benefits are realized and the timing of such cannot be assured. Any inability of management to successfully combine the operations of Emera and TECO Energy could have a material adverse effect on the Company's business, financial condition or results of operations.

Emera may not be successful in retaining the services of key personnel of TECO Energy following the Acquisition

Emera currently intends to retain key personnel of TECO Energy following the completion of the Acquisition and to continue to manage and operate TECO Energy as a separate operating company. Emera will compete with other potential employers for employees, and it may not be successful in keeping the services of the executives and other employees that it needs to realize the anticipated benefits of the Acquisition. The Company's failure to retain key personnel to remain as part of the management team of TECO Energy in the period following the Acquisition could have a material adverse effect on the business and operations of TECO Energy and Emera on a consolidated basis.

Emera is subject to risks associated with its results of operations and financing risks

Management of Emera believes, based on current expectations as to its future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available under its Revolving Facility and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Company's future performance reflect the current state of its information about TECO Energy and its operations and there can be no assurance that such information is correct and complete in all material respects.

After giving effect to the Acquisition, Emera will have a significant amount of debt, including US$4.1 billion of debt of TECO Energy assumed by Emera as a result of the Acquisition. As of March 31, 2016, on an as adjusted pro forma basis after giving effect to (i) the Acquisition Capital Markets Transactions; (ii) the issuance of the Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures); and (iii) the consummation of the Acquisition, details of which are included in the capitalization table provided herein, Emera would have approximately Cdn$15.5 billion of total indebtedness outstanding. See "Capitalization." The significant increase in the degree of the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; require Emera to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose Emera to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place Emera at a competitive disadvantage compared to its competitors that have less debt; make Emera vulnerable to any downturn in general economic conditions; and render Emera unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's and TECO Energy's indebtedness over time. There can be no assurance that any such indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of the Acquisition and working capital and future capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of distributions by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at TECO Energy and its subsidiaries

The business of TECO Energy is concentrated in Florida and New Mexico. While economic conditions in Florida and New Mexico have improved since the worst of the economic downturn in 2008, if they do not continue to improve or if they should worsen, retail customer growth rates may stagnate or decline, and customers' energy usage may further decline, adversely affecting TECO Energy's results of operations, net income and cash flows.

A factor in TECO Energy's customer growth in both Florida and New Mexico is net in migration of new residents, both domestic and non-U.S. A slowdown in the U. S. economy could reduce the number of new residents and slow customer growth. In addition, New Mexico has significant oil and natural gas production from the San Juan and Permian production basins. The current low oil and natural gas-price environment has reduced drilling activity and oil and natural gas production in some producing regions, which has reduced employment in those industries and industries that serve them. A continuation of these conditions could slow growth in the New Mexico economy, which could reduce earnings and cash flow from NMGC.

Developments in technology could reduce demand for electricity and gas

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy-efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity or transporting gas, or otherwise make the existing generating facilities of Tampa Electric uneconomic. In addition, advances in such technologies could reduce demand for electricity or natural gas, which could negatively impact the results of operations, net income and cash flows of TECO Energy and those of the Company following the Acquisition.

TECO Energy's businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations

TECO Energy's businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

PGS and NMGC, which typically have short but significant winter peak periods that are dependent on cold weather, are more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. NMGC typically earns all of its net income in the first and fourth quarters, due to winter weather. Mild winter weather could negatively impact results at TECO Energy and those of Emera following the Acquisition.

TECO Energy's electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce revenues or increase costs or competition

TECO Energy's electric and gas utilities operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC in Florida and the NMPRC in New Mexico, and Tampa Electric's wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on TECO Energy's utilities' financial performance by, for example, reducing revenues, increasing competition or costs, threatening investment recovery or impacting rate structure.

If Tampa Electric or PGS earn returns on equity above their respective allowed ranges, indicating an overearnings trend, those earnings could be subject to review by the FPSC. Ultimately, prolonged overearnings could result in credits or refunds to customers, which could reduce earnings and cash flow.

Various factors relating to the integration of NMGC could adversely affect TECO Energy's business and operations

The anticipated accretion to TECO Energy's earnings from NMGC during the original three-year integration period was based on estimates of synergies from the transaction and growth in the New Mexico economy, which are dependent on local and global economic conditions, normal weather and other factors, which may materially change, including:

- TECO Energy's estimate of NMGC's expected operating performance after the completion of the transaction may vary significantly from actual results.
- Over time, TECO Energy will be making significant capital investments to convert several NMGC computer systems to the systems that TECO Energy uses in Florida. These conversions may not be accomplished on time or on budget, which would increase costs for NMGC. In addition, the time required to convert these systems will cause NMGC to operate the existing systems past the end of their normal lives, which could reduce reliability.

- The potential loss of key employees of TECO Energy or NMGC who may be uncertain about their future roles in the TECO Energy / NMGC organization.

Negative impacts from these factors could have an adverse effect on the anticipated benefits of the Acquisition or TECO Energy's business, financial condition or results of operations. TECO Energy identified some, but not all, of the actions necessary to achieve its anticipated synergies. Accordingly, the synergies expected from the acquisition of NMGC may not be achievable in its anticipated amount or timeframe or at all.

Changes in the environmental laws and regulations affecting its businesses could increase TECO Energy's costs or curtail its activities

TECO Energy's businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on TECO Energy, requiring cost-recovery proceedings and/or requiring it to curtail some of its businesses' activities.

Regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs

The U.S. EPA published a new CCR rule in the U.S. Federal Register on April 17, 2015 setting federal standards for companies that dispose of or store CCRs in onsite landfills and impoundments. The rule went into effect on October 19, 2015 and contains design and operating standards for CCR management units. Tampa Electric is currently evaluating various options for demonstrating compliance with the rule. The initial assessment is that activities in 2016 will consist primarily of monitoring and testing of the two existing CCR impoundments that are affected by this rule. Potential capital expenditures that may be required to comply with this rule are not expected to be significant. This rule is likely to face continued legal challenges by the utility industry and environmental groups, and legislation may be required to fix certain portions of the rule. At this time, the ultimate outcome of any litigation or legislation is uncertain, so that it is not possible to predict the ultimate impact on Tampa Electric. While certain costs related to environmental compliance are currently recoverable from customers under Florida's ECRC, TECO Energy cannot be assured that any increased costs associated with the new regulations will be eligible for such treatment.

Federal or state regulation of GHG emissions, depending on how they are enacted and implemented, could increase TECO Energy's costs or the rates charged to TECO Energy customers, which could curtail sales

Among TECO Energy's companies, Tampa Electric has the most significant number of stationary sources with air emissions.

Current regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new state or federal environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new GHG emission regulation. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but TECO Energy cannot be assured that the FPSC would grant such recovery. Under the Clean Power Plan, each state is responsible for implementing its own regulations to accord to the federal standards. Accordingly, a change in Florida's regulatory landscape could significantly increase Tampa Electric's costs. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on TECO Energy requiring FPSC cost recovery proceedings and/or requiring it to curtail some of its business activities.

The Clean Power Plan establishes state-specific emission rate and mass-based goals measured against a 2012 baseline. As TECO Energy's investments in lower-GHG production largely occurred before 2012 and are factored into Florida's baseline generating capacity, TECO Energy may encounter more difficulty than its competitors in achieving cost-effective GHG emission reductions. Because the ultimate form of Florida's state plan remains unknown, the increased compliance costs that TECO Energy may face as a result of the Clean Power Plan are currently uncertain.

On February 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018.

In 2015, there was a proposed constitutional ballot initiative for the 2016 election approved by the Florida Supreme Court to promote increased direct sale and use of solar energy to generate electricity which has now been delayed to the 2018 election. There is a corresponding legislative proposal for the current 2016 legislative session that could, if successful, promote increased direct sale and use of solar energy to generate electricity

The potential amendment to the Florida constitution in 2018 and potential corresponding 2016 legislation would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and to allow sales of electricity by non-utility generators. Increased use of solar generation and sales by third parties would reduce energy sales and revenues at Tampa Electric. In addition, Tampa Electric could make investments in facilities to serve customers during periods that solar energy is not available that would not be profitable.

NMGC operates high-pressure natural gas transmission pipelines, which involve risks that may result in accidents or otherwise affect its operations

There are a variety of hazards and operating risks inherent in operating high-pressure natural gas transmission pipelines, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by floods, fires and other natural disasters that may cause substantial financial losses. In addition, these risks could result in significant injury, loss of life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, known as High Consequence Areas, the level of damage resulting from these risks could be greater. NMGC does not maintain insurance coverage against all of these risks and losses, and any insurance coverage it might maintain may not fully cover damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on TECO Energy's business, earnings, financial condition and cash flows.

NMGC's high-pressure transmission pipeline operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase TECO Energy's cost of operations and affect or limit its business plans

TECO Energy's pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation. These laws and regulations require TECO Energy to comply with a significant set of requirements for the design, construction, maintenance and operation of its pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of its pipelines. The regulations determine the pressures at which its pipelines can operate.

PHMSA is designing an integrity verification process intended to create standards to verify maximum allowable operating pressure, and to improve and expand pipeline integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. Pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on TECO Energy's pipelines. Should any of these risks materialize, it may have a material adverse effect on TECO Energy's operations, earnings, financial condition and cash flows.

Results at TECO Energy's companies may be affected by changes in customer energy-usage patterns

For the past several years, at Tampa Electric, and electric utilities across the United States, weather-normalized electricity consumption per residential customer has declined due to the combined effects of voluntary conservation efforts, economic conditions and improvements in lighting and appliance efficiency.

Forecasts by TECO Energy's companies are based on normal weather patterns and historical trends in customer energy-usage patterns. The ability of TECO Energy's utilities to increase energy sales and earnings could be negatively impacted if customers continue to use less energy in response to increased energy efficiency, economic conditions or other factors.

TECO Energy's computer systems and the infrastructure of its utility companies may be subject to cyber (primarily electronic or internet-based) or physical attacks, which could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems, or otherwise adversely affect its business and financial results and condition

There have been an increasing number of cyber-attacks on companies around the world, which have caused operational failures or compromised sensitive corporate or customer data. These attacks have occurred over the Internet, through malware, viruses, attachments to e-mails, through persons inside of the organization or through persons with access to systems inside of the organization.

TECO Energy has security systems and infrastructure in place that are designed to prevent such attacks, and these systems are subject to internal, external and regulatory audits to ensure adequacy. Despite these efforts, TECO Energy cannot be assured that a cyber-attack will not cause electric or gas system operational problems, disruptions of service to customers, compromise important data or systems, or subject it to additional regulation, litigation or damage to its reputation.

There have also been physical attacks on critical infrastructure at other utilities. While the transmission and distribution system infrastructure of TECO Energy's utility companies are designed and operated in a manner intended to mitigate the impact of this type of attack, in the event of a physical attack that disrupts service to customers, revenues would be reduced and costs would be incurred to repair any damage. These types of events, either impacting its facilities or the industry in general, could also cause TECO Energy to incur additional security- and insurance-related costs, and could have adverse effects on its business and financial results and condition.

Potential competitive changes may adversely affect TECO Energy's regulated electric and gas businesses

There is competition in wholesale power sales across the United States. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Although not expected in the foreseeable future, changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its expected performance.

The gas distribution industry has been subject to competitive forces for a number of years. Gas services provided by TECO Energy's gas utilities are unbundled for all non-residential customers. Because its gas utilities earn margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted TECO Energy's results. However, future structural changes that TECO Energy cannot predict could adversely affect PGS and NMGC.

Increased customer use of distributed generation could adversely affect TECO Energy's regulated electric utility business

In many areas of the United States there is growing use of rooftop solar panels, small wind turbines and other small-scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. Additionally, the EPA's Clean Power Plan could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets under the proposed rule.

Increased usage of distributed generation, particularly in those states where solar or wind resources are the most abundant, is reducing utility electricity sales but not reducing the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Continued utility investment that is not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

The value of TECO Energy's existing deferred tax benefits are determined by existing tax laws, and could be negatively impacted by changes in these laws

"Comprehensive tax reform" remains a topic of discussion in the U.S. Congress. Such legislation could significantly alter the existing tax code, including a reduction in corporate income tax rates. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would reduce the value of TECO Energy's existing deferred tax asset and could result in a charge to earnings from the write-down of that asset, and it would reduce future tax payments received by TECO Energy from its subsidiaries.

TECO Energy relies on some natural gas transmission assets that it does not own or control to deliver natural gas. If transmission is disrupted, or if capacity is inadequate, TECO Energy's ability to sell and deliver natural gas and supply natural gas to its customers and its electric generating stations may be hindered

TECO Energy depends on transmission facilities owned and operated by other utilities and energy companies to deliver the natural gas it sells to the wholesale and retail markets, as well as the natural gas it purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver products and satisfy its contractual and service obligations could be adversely affected.

Disruption of fuel supply could have an adverse impact on the financial condition of TECO Energy

Tampa Electric, PGS and NMGC depend on third parties to supply fuel, including natural gas and coal. As a result, there are risks of supply interruptions and fuel price volatility. Disruption of fuel supplies or transportation services for fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of locks and dams, pipeline failures or other events could impair the ability to deliver electricity or gas or generate electricity and could adversely affect operations. Further, the loss of coal suppliers or the inability to renew existing coal and natural gas contracts at favorable terms could significantly affect the ability to serve customers and have an adverse impact on the financial condition and results of operations of TECO Energy and those of the Company following the Acquisition.

Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses

TECO Energy's businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes in the availability of these commodities could affect the prices charged by suppliers as well as suppliers' operating costs and the competitive positions of their products and services.

In the case of Tampa Electric, fuel costs used for generation are affected primarily by the cost of coal and natural gas. Tampa Electric is able to recover prudently incurred costs of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

The ability to make sales of and the margins earned on wholesale power sales are affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of PGS and NMGC, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and, therefore, the competitive positions of PGS and NMGC as compared to electricity, other forms of energy and other gas suppliers.

The facilities and operations of TECO Energy could be affected by natural disasters or other catastrophic events

TECO Energy's facilities and operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures, vandalism, potentially catastrophic events such as the occurrence of a major accident or incident at one of the sites, and other events beyond the control of TECO Energy. The operation of transmission and distribution systems involves certain risks, including gas leaks, fires, explosions, pipeline ruptures and other hazards and risks that may cause unforeseen interruptions, personal injury or property damage. Any such incident could have an adverse effect on TECO Energy and any costs relating to such events may not be recoverable through insurance or recovered in rates. In certain cases, there is potential that such an event may not excuse TECO Energy's utility subsidiaries from servicing customers as required by their respective tariffs. In addition, TECO Energy may not be able to recover losses resulting from such events through insurance or rates.

The franchise rights held by TECO Energy's subsidiaries could be lost in the event of a breach by such TECO Energy subsidiary or could expire and not be renewed

TECO Energy's subsidiaries hold franchise rights that are memorialized in agreements with selected counterparties throughout the subsidiaries' service areas. In some cases these rights could be lost in the event of a breach of these agreements by such TECO Energy subsidiary. In addition, these agreements are for set periods and could expire and not be renewed upon expiration of the then-current terms. Selected agreements also contain purchase rights allowing municipalities to purchase the corresponding subsidiary's system within a given municipality's boundaries under certain conditions.

Tampa Electric, PGS and NMGC may not be able to secure adequate rights-of-way to construct transmission lines, gas interconnection lines and distribution related facilities and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers

Tampa Electric, PGS and NMGC rely on federal, state and local governmental agencies and, in particular in New Mexico, cooperation with local Native American tribes and councils to secure right-of-way and siting permits to construct transmission lines, gas interconnection lines and distribution-related facilities. If adequate right-of-way and siting permits to build new transportation and transmission lines cannot be secured:

- Tampa Electric, PGS and NMGC may need to remove its facilities, or abandon its facilities on, the property covered by rights-of-way or franchises and seek alternative locations for its transmission or distribution facilities;
- Tampa Electric, PGS and NMGC may need to rely on more costly alternatives to provide energy to their customers;
- Tampa Electric, PGS and NMGC may not be able to maintain reliability in their service areas; or
- Tampa Electric's, PGS's and NMGC's ability to provide electric or gas service to new customers may be negatively impacted.

Impairment testing of certain long-lived assets could result in impairment charges

TECO Energy assesses long-lived assets and goodwill for impairment annually or more frequently if events or circumstances occur that would more likely than not reduce the fair value of those assets below their carrying values. To the extent the value of goodwill or a long-lived asset becomes impaired, TECO Energy may be required to record non-cash impairment charges that could have a material adverse impact on TECO Energy's financial condition and results from operations. In connection with the NMGC acquisition, TECO Energy recorded additional goodwill and long-lived assets that could become impaired.

TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility

TECO Energy has substantial indebtedness, which has resulted in fixed charges it is obligated to pay. The level of TECO Energy's indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing.

TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial covenants as defined in the applicable agreements to borrow under their respective credit facilities. Also, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments.

Although TECO Energy was in compliance with all required financial covenants as of March 31, 2016, it cannot assure compliance with these financial covenants in the future. TECO Energy's failure to comply with any of these covenants or to meet its payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a portion of its outstanding obligations. If TECO Energy's cash flows and capital resources are insufficient to fund its debt service obligations, it may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance its indebtedness. TECO Energy's ability to restructure or refinance its debt will depend on the condition of the capital markets and TECO Energy's financial condition at such time. Any refinancing of TECO Energy's debt could be at higher interest rates and may require TECO Energy to comply with more onerous covenants, which could further restrict TECO Energy's business operations. The terms of existing or future debt instruments may restrict TECO Energy from adopting some of these alternatives.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates that do not appear on its balance sheet. Such obligations include guarantees, letters of credit and certain other types of contractual commitments.

Financial market conditions could limit TECO Energy's access to capital and increase TECO Energy's costs of borrowing or refinancing, or have other adverse effects on its results

TECO Finance and TEC have debt maturing in 2016 and subsequent years which may need to be refinanced. Future financial market conditions could limit TECO Energy's ability to raise the capital it needs and could increase its interest costs, which could reduce earnings. If TECO Energy is not able to issue new debt, or TECO Energy issues debt at interest rates higher than expected, its financial results or condition could be adversely affected.

TECO Energy enters into derivative transactions, primarily with financial institutions as counterparties. Financial market turmoil could lead to a sudden decline in credit quality among these counterparties, which could make in-the-money positions uncollectable

TECO Energy enters into derivative transactions with counterparties, most of which are financial institutions, to hedge its exposure to commodity price and interest rate changes. Although TECO Energy believes it has appropriate credit policies in place to manage the non-performance risk associated with these transactions, turmoil in the financial markets could lead to a sudden decline in credit quality among these counterparties. If such a decline occurs for a counterparty with which TECO Energy has an in-the-money position, TECO Energy could be unable to collect from such counterparty.

Declines in the financial markets or in interest rates used to determine benefit obligations could increase TECO Energy's pension expense or the required cash contributions to maintain required levels of funding for its plan

Under calculation requirements of the Pension Protection Act of 2006, as amended, as of the January 1, 2015 measurement date, TECO Energy's pension plan was essentially fully funded. Under MAP 21, TECO Energy is not required to make additional cash contributions over the next five years; however TECO Energy may make additional cash contributions from time to time. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund its pension plan in the future, and could cause pension expense to increase.

TECO Energy's financial condition and results could be adversely affected if its capital expenditures are greater than forecast

In 2016, TECO Energy is forecasting capital expenditures at Tampa Electric to support the current levels of customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to maintain transmission and distribution system reliability, to maintain coal-fired generating unit reliability and efficiency, and to add generating capacity at the Polk Power Station. TECO Energy is forecasting capital expenditures at PGS to support customer growth, system reliability, conversion of customers from other fuels to natural gas and to replace bare steel and cast iron pipe. Forecasted capital expenditures at NMGC are expected to support customer and system reliability and expansion.

If TECO Energy's capital expenditures exceed the forecasted levels, it may need to draw on credit facilities or access the capital markets on unfavorable terms. TECO Energy cannot be sure that it will be able to obtain additional financing, in which case its financial position could be adversely affected.

TECO Energy's financial condition and ability to access capital may be materially adversely affected by ratings downgrades to below investment grade and TECO Energy cannot be assured of any rating improvements in the future

A downgrade to below investment grade by any rating agencies may affect TECO Energy's ability to borrow, may change requirements for future collateral or margin postings, and would increase financing costs, which may decrease earnings. TECO Energy may also experience greater interest expense than it may have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rates due to any downgrades. In addition, downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

If the ratings of TEC or NMGC decline to below investment grade, Tampa Electric, PGS or NMGC, as applicable, could be required to post collateral to support their purchases of electricity and gas.

In connection with the sale of TECO Coal to Cambrian, TECO Energy temporarily retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the completion of the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia

These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments by TECO Energy to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder or TECO Coal or one of the affiliates transferred to Cambrian Coal Corp ("Cambrian") as part of the sale did not pay the surety company. Pursuant to the Securities Purchase Agreement (the “TECO Coal SPA”) for the sale of TECO Coal LLC (“TECO Coal”) to Cambrian, Cambrian is obligated to file applications required in connection with the change of ownership and control of TECO Coal and its affiliates with the appropriate governmental entities with respect to the coal mining permits. Pursuant to the terms of the TECO Coal SPA, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond(s) secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy’s indemnity are released, TECO Energy’s indemnity will remain effective. TECO Energy is working with Cambrian on the process of replacing the bonds and expects the process to be completed in 2016.

Risks Related to the Notes

Rights only as an Equity Holder in the Event of Insolvency

In the event of the occurrence of the Automatic Conversion, with the result that the holder of a series of Notes receives Conversion Preferred Shares on conversion of such series of Notes, the only claim or entitlement of such holder will be in its capacity as a shareholder of Emera. See “Description of Notes—Automatic Conversion” and “Risks Related in an Investment in Conversion Preferred Shares—Insolvency or Winding-Up”.

Liquidity of and Dealings in Notes

It is not expected that the Notes will be listed on any stock exchange. This may affect the pricing of the Notes in the secondary market, the transparency and availability of trading prices, and the liquidity of the Notes. There can be no assurance that an active trading market will develop or be sustained or that the Notes may be resold at or above the initial public offering price. The ability of a holder to pledge Notes or otherwise take action with respect to such holder’s interest in Notes (other than through a Participant) may be limited due to the lack of a physical certificate.

Subordination

Emera’s obligations under the Notes will be subordinated in right of payment to all of Emera’s current and future Senior Indebtedness. This means that Emera will not be permitted to make any payments on the Notes if it defaults on a payment of principal of, premium, if any, or interest on any such Senior Indebtedness or there shall occur an event of default under such Senior Indebtedness and it does not cure the default within the applicable grace period, if the holders of the Senior Indebtedness have the right to accelerate the maturity of such indebtedness or if the terms of such Senior Indebtedness otherwise restrict Emera from making payments to junior creditors. Emera’s guarantee of the Senior Guaranteed Notes to be issued by Emera US Finance and any Senior Notes to be issued by Emera in each case as part of the Acquisition Capital Markets Transactions, will constitute Senior Indebtedness of Emera. See “Description of the Notes—Subordination”.

In addition to the contractual subordination described above, the payment of principal of, premium, if any, and interest on the Notes will be structurally subordinated to any indebtedness and other liabilities of Emera’s subsidiaries.

Emera’s Senior Indebtedness as of March 31, 2016 was approximately Cdn$751 million. As of March 31, 2016, Emera’s subsidiaries had approximately Cdn$2,247 million of outstanding indebtedness that will effectively rank senior to the Notes.

Furthermore, in the event of an insolvency or liquidation of Emera, the claims of creditors of Emera would be entitled to a priority payment over the claims of holders of equity interests of Emera, such as the Conversion Preferred Shares. See “Risks Related to the Notes—Rights only as an Equity Holder in the Event of Insolvency” and “Risks Related to an Investment in Conversion Preferred Shares—Insolvency or Winding-up”.

No Limit on Debt

The Trust Indenture does not contain any provision limiting Emera's ability to incur indebtedness generally. Any such indebtedness could rank in priority to the Notes. Emera currently has substantial indebtedness and may incur substantial additional indebtedness in the future.

Early Redemption

Emera may redeem the Notes in the circumstances described in this Prospectus or any Prospectus Supplement relating to the applicable series of Notes. This redemption right may, depending on prevailing market conditions at the time, create reinvestment risk for holders of the Notes in that they may be unable to find a suitable replacement investment with a comparable return to the Notes.

Deferral Right

Unless Emera has paid all accrued and payable interest on the Notes, subject to certain exceptions, Emera may elect, at its sole option, to defer the interest payable on any series of Notes on one or more occasions for up to five consecutive years as described under "Description of the Notes—Deferral Rights". There is no limit on the number of Deferral Events that may occur. Such deferral will not constitute an event of default or any other breach under the Notes and the Trust Indenture.

Interest in Respect of Deferral Events

During any deferral period, the Notes will be treated as issued with OID at the time of such deferral and all stated interest due after such deferral will be treated as OID. Consequently, a U.S. holder of Notes would be required to include OID in its gross income in the manner described under the heading "Certain U.S. Federal Income Tax Considerations" even though Emera would not make any actual cash payments to holders of Notes during a deferral period.

Investors in the Notes located outside of Canada may have difficulties enforcing civil liabilities

Emera is incorporated under the laws of Nova Scotia. Moreover, substantially all of Emera's directors, controlling persons and officers, as well as certain of the experts named in this Prospectus, are residents of Canada or other jurisdictions outside of the United States, and all or a substantial portion of their assets and a substantial portion of Emera's assets are located outside of the United States. Emera will agree, in accordance with the terms of the Trust Indenture, to accept service of process in any suit, action or proceeding with respect to the Trust Indenture or the Notes brought in any federal or state court located in New York City by an agent designated for such purpose, and to submit to the jurisdiction of such courts in connection with such suits, actions or proceedings. Nevertheless, it may be difficult for holders of the Notes to effect service of process within the United States upon directors, officers and experts who are not residents of the United States or to realize in the United States upon judgments of courts of the United States predicated upon civil liability under U.S. federal or state securities laws or other laws of the United States. In addition, there is doubt as to the enforceability in Canada against Emera or against Emera's directors, officers and experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of courts of the United States, of liabilities predicated solely upon U.S. federal or state securities laws.

An increase in interest rates could result in a decrease in the relative value of the Notes

In general, as market interest rates rise, notes bearing interest at a fixed rate generally decline in value because the premium, if any, over market interest rates will decline. Consequently, if you purchase Notes and market interest rates increase, the market value of your Notes may decline. We cannot predict future levels of market interest rates.

Emera is a holding company

Emera is a holding company and depends on dividends and other distributions from its subsidiaries. Emera conducts substantially all its operations through subsidiaries, and those subsidiaries generate substantially all of its operating income and cash flow. As a result, distributions or advances from those subsidiaries are the principal source of funds necessary to meet the debt service obligations of Emera. Contractual provisions or laws, as well as the subsidiaries' financial condition and operating requirements, may limit the ability of Emera to obtain cash from its subsidiaries that it requires to pay its debt service obligations, including any payments required to be made under the Notes.

The tax treatment of the Notes for U.S. federal income tax purposes is uncertain

The treatment of the Notes for U.S. federal income tax purposes is uncertain. The determination of whether an obligation represents a debt or equity interest is based on all the relevant facts and circumstances at the time the obligation is issued. There is no direct legal authority as to the proper U.S. federal income tax treatment of an instrument such as the Notes that is denominated as a debt instrument and has certain significant debt features, but that provides for a possible Automatic Conversion under which an investor could lose its creditor rights upon the occurrence of an Automatic Conversion Event. In the absence of authority addressing the proper characterization of instruments such as the Notes, to the extent required to do so, we intend to treat the Notes as debt for U.S. federal income tax purposes. However, we will not request any ruling from the U.S. Internal Revenue Service, or the IRS, regarding the treatment of the Notes for U.S. federal income tax purposes and the IRS or a court may conclude that the Notes should be treated as equity for U.S. federal income tax purposes.

If the Notes were treated as equity for U.S. federal income tax purposes and we were a "passive foreign investment company," or PFIC, for any taxable year during which a U.S. investor held the Notes, the U.S. investor could be subject to adverse tax consequences, including increased tax liability on certain gains and payments on the Notes and a requirement to file annual reports with the IRS. We believe that we were not a PFIC for our 2015 taxable year and do not expect to be a PFIC for our 2016 taxable year. However, because the composition of our income and assets will vary over time, and because there are uncertainties in the characterization of certain of our income and assets for PFIC purposes, there can be no assurance that we will not be a PFIC for any taxable year.

Prospective investors should consult their tax advisers as to the proper characterization of the Notes for U.S. federal income tax purposes and the consequences of holding a Note if we are or become a PFIC. See "Certain U.S. Federal Income Tax Considerations."

If interest payments on the Notes were deferred, U.S. investors would be required to recognize income for U.S. federal income tax purposes in advance of the receipt of cash attributable to such income

In the event we exercise our option to defer payments of interest, the Notes would be treated as retired and reissued for U.S. federal income tax purposes and U.S. investors would be required to treat all stated interest on the deemed reissued Notes as original issue discount, or OID. Consequently, during any period of interest deferral, and any period thereafter, U.S. investors will include all stated interest in gross income as it accrues using a constant yield method before the receipt of cash. See "Certain U.S. Federal Income Tax Considerations."

Risks Related to an Investment in Conversion Preferred Shares

Dividends

Holders of Conversion Preferred Shares do not have a right to dividends on such shares unless declared by the Board of Directors. The declaration of dividends is in the discretion of the Board of Directors even if Emera has sufficient funds, net of its liabilities, to pay such dividends. Emera may not declare or pay a dividend if there are reasonable grounds for believing that (i) Emera is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of Emera's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares. Liabilities of Emera will include those arising in the course of its business, indebtedness, including inter-company debt, and amounts, if any, that are owing by Emera under guarantees in respect of which a demand for payment has been made. In addition, a dividend (including a deemed dividend) received on a series of Conversion Preferred Shares may be subject to Canadian non-resident withholding tax and, if any such dividends are so subject, no additional amounts will be payable to holders of such series of Conversion Preferred Shares in respect of such withholding tax. See "Certain Canadian Federal Income Tax Considerations—Conversion Preferred Share—Dividends".

Insolvency or Winding-Up

The Conversion Preferred Shares do not constitute indebtedness and are equity capital of Emera which rank junior to all indebtedness and other non-equity claims and equally with the other outstanding series of Emera's First Preferred Shares in the event of an insolvency or winding-up of Emera. If Emera becomes insolvent or is wound up, Emera's assets must be used to pay liabilities and other debt before payments may be made on the Conversion Preferred Shares and other First Preferred Shares, if any.

No Fixed Maturity

The Conversion Preferred Shares do not have a fixed maturity date and are not redeemable at the option of the holders of the Conversion Preferred Shares. The ability of a holder to liquidate its holdings of Conversion Preferred Shares may be limited.

Voting Rights

Holders of Conversion Preferred Shares will not have any voting rights except in the event of the non-payment of eight quarterly dividends, subject to certain constraints, as described under "Description of Conversion Preferred Shares—Voting Rights", and "Description of Conversion Preferred Shares—Consideration Shares Ownership," or otherwise required by law.

Secondary Market and Liquidity

There can be no assurance that an active trading market will develop for the Conversion Preferred Shares following the issuance of any of those shares, or if developed, that such a market will be liquid or sustained at the issue price of such shares. Emera is under no obligation to list the Conversion Preferred Shares on any stock exchange or other market. The ability of a holder to pledge Conversion Preferred Shares or otherwise take action with respect to such holder's interest therein (other than through a Participant) may be limited due to the lack of a physical certificate.

Market Value

The market value of the Conversion Preferred Shares may fluctuate due to a variety of factors relative to Emera's business, including announcements of new developments, fluctuations in Emera's operating results, sales of Emera Preferred Shares, failure to meet analysts' expectations, the impact of various tax laws or rates and general market conditions or the worldwide economy. There can be no assurance that the market value of the Conversion Preferred Shares will not experience significant fluctuations in the future, including fluctuations that are unrelated to Emera's performance. Prevailing yields on similar securities will affect the market value of the Conversion Preferred Shares. Assuming all other factors remain unchanged, the market value of the Conversion Preferred Shares would be expected to decline as prevailing yields for similar securities rise and would be expected to increase as prevailing yields for similar securities decline. Spreads over LIBOR and comparable benchmark rates of interest for similar securities will also affect the market value of the Conversion Preferred

Shares in an analogous manner. In addition, the market value of the Conversion Preferred Shares will be significantly adversely affected in the event that dividends are not paid on such shares. See “Risks Related to an Investment in Conversion Preferred Shares—Dividends”.

USE OF PROCEEDS

The net proceeds of any offering of Notes will be used as set forth in the applicable Prospectus Supplement. Such uses may include, financing, directly or indirectly, part of the purchase price payable for the Acquisition (including, Acquisition-Related Expenses) and to reduce any amounts outstanding under the Acquisition Credit Facilities, to the extent any amounts are drawn on such facilities in connection with the Acquisition.

CAPITALIZATION

The following table sets out Emera's cash and cash equivalents and consolidated capitalization as at March 31, 2016 and on an as adjusted basis, as at such date after giving effect to (i) the Acquisition Capital Markets Transactions, (ii) the issuance of Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures), and (iii) consummation of the Acquisition. See "Unaudited Pro Forma Consolidated Financial Statements" and "Summary—Financing the Acquisition" herein and the unaudited condensed consolidated interim financial statements of each of Emera and TECO Energy as at and for the three months ended March 31, 2016, which are incorporated by reference herein.

	As at March 31, 2016 (unaudited)	As adjusted as at March 31, 2016 (unaudited)
	millions of Canadian dollars	
Cash and cash equivalents	$ 999.5	323.2
Indebtedness:		
Current portion of long-term debt(1)(2)	272.6	380.6
Short-term debt(2)	10.2	675.6
Other Long-term debt(2)	3,714.2	8,180.1
Convertible Debentures(3)	681.8	—
Acquisition Capital Markets Transactions(4)	—	6,575.6
Total debt (net of cash)	3,679.3	15,488.7
Shareholders' equity:		
Common Shares(3)	2,199.0	4,321.8
First Preferred Shares	709.5	709.5
Additional contributed surplus	35.3	35.3
Accumulated other comprehensive income	5.8	5.8
Retained earnings(5)	1,142.1	996.0
Total shareholders' equity	4,091.7	6,068.3
Total capitalization(6)	7,771	21,557.0

(1) Current portion of long-term debt includes Cdn$250 million of the Emera 2.96% senior unsecured notes due 2016. See "Description of Other Indebtedness—Emera MTN notes."

(2) Other Long-term debt, Current portion of long-term debt and Short-term debt as adjusted at March 31, 2016 give effect to consummation of the Acquisition and assumption by Emera of Cdn$5,356 million of TECO Energy, of which Cdn$4,583.5 million is classified "long-term debt," Cdn$108 million is classified "current portion of long-term debt" and Cdn$665 is classified "short-term debt", but does include any indebtedness represented by the Acquisition Capital Markets Transactions, including any series of Notes offered hereunder.

(3) Convertible Debentures as at March 31, 2016 reflects the first instalment of the Convertible Debentures. Convertible Debentures and Common Shares as adjusted at March 31, 2016 gives effect to the issuance of the Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the remaining Cdn$1,457 million in the Final Instalment of the Convertible Debentures). See "Management's Discussion and Analysis—Convertible Debentures Represented by Instalment Receipts" and "Description of Other Indebtedness—Convertible Debenture Offering".

(4) Emera intends to raise up to Cdn$6.6 billion in aggregate principal amount in the Acquisition Capital Markets Transactions. Acquisition Capital Markets Transactions as adjusted at March 31, 2016 assumes consummation of the Acquisition Capital Markets Transactions. The aggregate principal amounts raised by each of the other Acquisition Capital Markets Transactions are dependent on market and other conditions, and may vary. To the extent Emera raises less than Cdn$6.6 billion in connection with the Acquisition Capital Markets Transactions, Emera intends to pay any shortfall by drawing on the Acquisition Credit Facilities and/or using existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) or other sources available to Emera in order to consummate the Acquisition. See "Description of Other Indebtedness—Acquisition Credit Facilities."

(5) Retained Earnings as adjusted at March 31, 2016 gives effect to the consummation of the Acquisition and reflects, among other things (i) Cdn$28 million of interest costs on the Convertible Debentures, and (ii) estimated Acquisition Related Expenses of Cdn$117 million.

(6) Excludes non-controlling interests.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited pro forma consolidated financial information is presented to illustrate the estimated effects of (i) the Acquisition Capital Markets Transactions, (ii) the issuance of Common Shares upon conversion of the Convertible Debentures on the Final Instalment Date (assuming payment in full of the Final Instalment of the Convertible Debentures) and (iii) the consummation of the Acquisition. For additional information see "—Notes to the Unaudited Pro Forma Consolidated Financial Statements—Note 2: Description of Transactions." The unaudited pro forma consolidated balance sheet gives effect to the Acquisition Capital Markets Transactions, the issuance of the Common Shares (as described above) and the Acquisition as if they closed on March 31, 2016. The unaudited pro forma consolidated statements of earnings for the year ended December 31, 2015 and the three months ended March 31, 2016 give effect to the Acquisition and the Acquisition Capital Markets Transactions as if they had closed on January 1, 2015.

The unaudited pro forma consolidated financial statements are presented for illustrative purposes only. The pro forma adjustments are based upon available information and certain assumptions that we believe are reasonable in the circumstances, as described in the notes to the unaudited pro forma consolidated financial statements.

The unaudited pro forma consolidated financial statements are based on TECO Energy's consolidated financial statements as at and for the three months ended March 31, 2016 and for the year ended December 31, 2015. For more information regarding the foreign exchange translation from U.S. Dollars to Canadian Dollars for TECO Energy's financial statements see "—Notes to the Unaudited Pro Forma Consolidated Financial Statements—Note 3(j): Foreign Exchange Translations." TECO Coal was sold in 2015 and as a result, the operating results of the TECO Coal segment are reported as discontinued operations.

The pro forma information presented, including allocation of purchase price, is based on preliminary estimates of fair values of assets acquired and liabilities assumed, available information and assumptions and may be revised as additional information becomes available. The actual adjustments to the consolidated financial statements upon the closing of the Acquisition will depend on a number of factors, including additional information available and the net assets of TECO Energy on the closing date of the Acquisition. Therefore, the actual adjustments will differ from the pro forma adjustments, and the differences may be material. For example, the final purchase price allocation is dependent on, among other things, the finalization of asset and liability valuations. A final determination of these fair values will reflect an independent third-party valuation. This final valuation will be based on the actual net tangible and intangible assets and liabilities of TECO Energy that exist as of the closing date of the Acquisition. Any final adjustment may change the allocation of purchase price, which could affect the fair value assigned to the assets and liabilities and could result in a change to the unaudited pro forma consolidated financial statements, including a change to goodwill.

The unaudited pro forma consolidated financial statements should be read in conjunction with the information contained in "Caution Regarding Unaudited Pro Forma Consolidated Financial Statements," "Summary—The Acquisition," "Summary—Financing the Acquisition," "Summary—Summary Historical and Pro Forma Financial Data," "Management's Discussion and Analysis" and the audited and unaudited consolidated financial statements and the related notes incorporated by reference in this Prospectus. All pro forma adjustments and their underlying assumptions are described more fully in "—Notes to the Unaudited Pro Forma Consolidated Financial Statements."

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS FOR THE YEAR ENDED DECEMBER 31, 2015

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Statement of Earnings
	millions of Canadian dollars, except for per share amounts				
Operating Revenues					
Regulated	2,193	3,493			5,686
Non-regulated	596	15			611
Total Operating Revenues	2,789	3,508		—	6,298
Operating Expenses					
Regulated fuel for generation and purchased power[1]	815	2,049			2,863
Regulated fuel adjustment mechanism and fixed cost deferrals	42				42
Non-regulated fuel for generation and purchased power	336				336
Non-regulated direct costs	20				20
Operating, maintenance and general	667	29	3(i)	(13)	
			3(i)	(22)	661
Provincial, state and municipal taxes	64	265			329
Depreciation and amortization	340	446			786
Total Operating Expenses	2,282	2,790		(35)	5,036
Income from operations	508	719		35	1,261
Income from equity investments	109				109
Other income (expenses)	141	27	3(i)	(119)	49
Interest expense, net	213	238	3(i)	(40)	
			3(i)	(23)	
			3(d)	284	
			3(e)	12	684
Income before provision for income taxes	545	507		(317)	735
Income tax expense (recovery)	92	199	3(i)	23	
			3(i)	(18)	
			3(i)	5	
			3(d)	(103)	197
Net income from continuing operations	452	308		(223)	538
Discontinued Operations					
Income (loss) from discontinued operations		(136)			(136)
Provision (benefit) for income taxes		(49)			(49)
Income (loss) from discontinued operations, net		(87)			(87)
Non-controlling interest in subsidiaries	25				25
Net income of Emera Incorporated	428	222		(223)	426
Preferred stock dividends	30				30
Net income attributable to common shareholders	397	222		(223)	396
Adjusted Net income attributable to common shareholders[2]	330	222		(223)	329
Weighted average shares of common stock outstanding (in millions)					
Basic	145.80		3(h)	52.21	198.01
Diluted	146.40		3(h)	52.21	198.61
Earnings per common share					
Basic	2.72				2.00
Diluted	2.71				1.99

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Statement of Earnings
	millions of Canadian dollars, except for per share amounts				
Adjusted Net Income per common share[2]					
Basic	2.26				1.66
Diluted	2.25				1.65
Earnings per common share excluding discontinued operations					
Basic	2.72				2.44
Diluted	2.71				2.43
Dividends per common share declared	1.66				

(1) The TECO Energy statement of earnings includes maintenance costs in regulated fuel for generation and purchased power and the cost of gas sold by the regulated gas distribution companies.

(2) Adjusted Net Income attributable to common shareholders and Adjusted Net Income per common share are non-U.S. GAAP measures, adjusting for the earnings effect of Emera's mark-to-market adjustments. Non-U.S. GAAP measures are not recognized measures under U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. See "Presentation of Financial Information."

See accompanying Notes to Unaudited Pro Forma Consolidated Financial Statements.

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS FOR THE QUARTER END MARCH 31, 2016

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Statement of Earnings
	millions of Canadian dollars (except for per share amounts)				
Operating Revenues					
Regulated	587	902			1,489
Non-regulated	290	4			295
Total Operating Revenues	877	907			1,784
Operating Expenses					
Regulated fuel for generation and purchased power[1]	198	507			705
Regulated fuel adjustment mechanism and fixed cost deferrals	18				18
Non-regulated fuel for generation and purchased power	110				110
Non-regulated direct costs	2				2
Operating, maintenance and general	176			(0)	175
Provincial, state and municipal taxes	16	73			89
Depreciation and amortization	88	123			211
Total Operating Expenses	607	703		(0)	1,310
Income from operations	270	204		0	474
Other income (expenses)	(113)	10	3(i)	140	36
Interest expense, net	75	63	3(i)	(4)	
			3(i)	(22)	
			3(i)	1	
			3(d)	76	
			3(d)	3	192
Income before provision for income taxes	82	150		86	318
Income tax expense (recovery)	27	49	3(i)	8	
			3(i)	18	
			3(d)	(28)	75
Net income from continuing operations	55	101		87	243
Discontinued Operations					
Income (loss) from discontinued operations		0			0
Provision (benefit) for income taxes		0			0
Income (loss) from discontinued operations, net		0			0
Non-controlling interest in subsidiaries	4				4
Net income of Emera Incorporated	51	101		87	240
Preferred stock dividends	7				7
Net income attributable to common shareholders	44	101		87	233
Adjusted Net income attributable to common shareholders[2]	120	101		87	309
Weighted average shares of common stock outstanding (in millions)					
Basic	148.70		3(h)	52.21	200.91
Diluted	149.30		3(h)	52.21	201.51

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Statement of Earnings
	millions of Canadian dollars (except for per share amounts)				
Earnings per common share					
Basic	0.30				1.16
Diluted	0.30				1.16
Adjusted Net Income per common share[(2)]					
Basic	0.81				1.54
Diluted	0.81				1.53
Earnings per common share excluding discontinued operations					
Basic	0.30				1.16
Diluted	0.30				1.16
Dividends per common share declared	0.48				

See accompanying Notes to Unaudited Pro Forma Consolidated Financial Statements.

(1) The TECO Energy statement of earnings includes maintenance costs in regulated fuel for generation and purchased power and the cost of gas sold by the regulated gas distribution companies.

(2) Adjusted Net Income attributable to common shareholders and Adjusted Net Income per common share are non-U.S. GAAP measures, adjusting for the earnings effect of Emera's mark-to-market adjustments. Non-U.S. GAAP measures are not recognized measures under U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. See "Presentation of Financial Information."

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET
AS AT MARCH 31, 2016

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Balance Sheet
	millions of Canadian dollars				
ASSETS					
Current assets					
Cash and cash equivalents	1,000	60	3(b)	(8,423)	
			3(c)	1,457	
			3(c)	(44)	
			3(c)	(42)	
			3(d)	6,576	
			3(d)	(118)	
			3(e)	(141)	323
Restricted cash	22				22
Receivables, net	610	311			922
Income taxes receivable	16				16
Inventory	261	253			514
Derivative instruments	92				92
Regulatory assets	78	52			130
Prepaid expenses	40	33			73
Due from related parties	2				2
Other current assets	168				168
Total current assets	2,289	709		(736)	2,263
Property, plant and equipment, net of accumulated depreciation	6,015	9,797			15,812
Other assets					
Income taxes receivable	48				48
Deferred income taxes	47		3(c)	28	
			3(c)	14	
			3(e)	24	113
Derivative instruments	85				85
Pension and post-retirement asset	9				9
Regulatory assets	619	510			1,129
Net investment in direct financing lease	479				479
Investments subject to significant influence	1,210				1,210
Available-for-sale investments	106				106
Goodwill	248	530	3(b)	(530)	
			3(b)	5,660	5,908
Intangibles, net of accumulated amortization	191				191
Due from related parties	3				3
Other long-term assets	100	103			203
Total other assets	3,144	1,143		5,196	9,483
	11,449	11,649		4,460	27,558

	Emera	TECO Energy	Note	Pro Forma Adjustments	Pro Forma Consolidated Balance Sheet
		millions of Canadian dollars			
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities					
Short-term debt	10	665			676
Current portion of long-term debt	273	108			381
Accounts payable	372	475			846
Income taxes payable	9	37			45
Convertible Debentures represented by instalment receipts	682		3(c)	(682)	
Derivative instruments	148	29			177
Regulatory liabilities	75	141			216
Pension and post-retirement liabilities	7	27			34
Due to related party	2				2
Other current liabilities	183	75			258
Total current liabilities	1,760	1,557		(682)	2,635
Long-term liabilities					
Long-term debt	3,714	4,526	3(d)	6,458	
			3(b)	57	14,756
Deferred income taxes	794	787			1,581
Derivative instruments	79	1			80
Regulatory liabilities	221	920			1,141
Asset retirement obligations	116				116
Pension and post-retirement liabilities	296	360			656
Other long-term liabilities	272	147			420
Total long-term liabilities	5,492	6,743		6,515	18,750
Shareholder's Equity					
Common stock	2,199	305	3(g)	(305)	
			3(c)	2,185	
			3(c)	(62)	4,322
Cumulative preferred stock	710				710
Contributed surplus	35	2,458	3(g)	(2,458)	35
Accumulated other comprehensive loss	6	(15)	3(g)	15	6
Retained earnings	1,142	601	3(g)	(601)	
			3(e)	(141)	
			3(e)	24	
			3(c)	(42)	
			3(c)	14	996
Total Emera Incorporated equity	4,092	3,350		(1,373)	6,068
Non-controlling interest in subsidiaries	105				105
Total equity	4,197	3,350		(1,373)	6,173
Total liabilities and equity	11,449	11,649		4,460	27,558

See accompanying Notes to Unaudited Pro Forma Consolidated Financial Statements.

Notes to Unaudited Pro Forma Consolidated Financial Statements

As at and for the three months ended March 31, 2016 and for the year ended December 31, 2015

(in millions of Canadian dollars, unless otherwise stated)

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma consolidated financial information is presented to illustrate the estimated effects of (i) the Acquisition Capital Markets Transactions, (ii) the issuance of Common Shares upon conversion of the Convertible Debentures (assuming payment in full of the Final Instalment of the Convertible Debentures) and (iii) the consummation of the Acquisition. The accompanying unaudited pro forma consolidated financial statements have been prepared by management of Emera and are derived from the unaudited and audited consolidated financial statements of Emera as at and for the three months ended March 31, 2016 and for the year ended December 31, 2015, respectively, and the unaudited and audited consolidated financial statements of TECO Energy (refer to footnote 3(j) below for further consideration of the foreign exchange translation) as at and for the three months ended March 31, 2016 and for the year ended December 31, 2015, respectively.

The accompanying unaudited pro forma consolidated financial statements utilize accounting policies that are consistent with those disclosed in Emera's and TECO Energy's audited consolidated financial statements and were prepared in accordance with U.S. accounting principles.

The Acquisition has been accounted for using the acquisition method. The purchase price is primarily based upon the regulated assets and liabilities at the date of closing. Based on the purchase price calculation as detailed in the Acquisition Agreement, the estimated net purchase price for the equity of TECO Energy is approximately Cdn$8.6 billion. See "—Note 3(b): Allocation of the Estimate Net Purchase Price."

The accompanying unaudited pro forma consolidated balance sheet and unaudited pro forma consolidated statements of earnings reflect the Acquisition as if it had closed on March 31, 2016 and January 1, 2015, respectively. The accompanying unaudited pro forma consolidated financial statements may not be indicative of the results that would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon Emera's estimation of such assets and liabilities following the closing of the Acquisition and, accordingly, the final purchase price allocation, as it relates principally to goodwill, may differ materially from the preliminary allocation reflected herein. Also, the actual blended interest rate payable on the indebtedness issued in the Acquisition Capital Markets Transactions (and, if necessary, incurred under the Acquisition Credit Facilities) may differ materially from the estimated blended interest rate reflected herein.

The accompanying unaudited pro forma consolidated financial statements should be read in conjunction with the description of the Acquisition and the proposed financing thereof provided elsewhere in this Prospectus; the audited and unaudited consolidated financial statements of TECO Energy, including the notes thereto, incorporated by reference in this Prospectus, and the audited and unaudited consolidated financial statements of Emera, including the notes thereto, incorporated by reference in the Prospectus.

The underlying assumptions for the pro forma adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Acquisition. In addition, the unaudited pro forma consolidated financial statements do not reflect any of the synergies or cost reductions that may result from the Acquisition and do not include any restructuring costs or other one-time charges that may be incurred. These pro forma adjustments are based on currently available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, it is expected that the actual adjustments will differ from the pro forma adjustments, and the differences may be material.

2. DESCRIPTION OF TRANSACTIONS

Pursuant to the Acquisition Agreement among Emera, Emera US Inc., a direct wholly-owned subsidiary of Emera US Holdings Inc. and TECO Energy, Emera will indirectly purchase all of the outstanding common shares of TECO Energy for US$27.55 per share. The estimated net purchase price, including (i) payment for unexercised stock options and performance shares and restricted stock units with the applicable number of shares included in the share count used in the purchase price calculation; and (ii) estimated acquisition costs of Cdn$130 million after tax, will be approximately Cdn$8.6 billion. Emera will also assume TECO Energy's consolidated debt, which was approximately as adjusted Cdn$5.4 billion as at March 31, 2016 as described herein.

Emera has arranged two committed debt bridge facilities: (i) a US$4.3 billion bridge facility repayable in full on the first anniversary following its advance, and (ii) a US$2.2 billion bridge facility repayable in full on the first anniversary following its advance, which, together with existing cash and other sources available to Emera, an existing Revolving Facility, the Convertible Debentures and Acquisition Capital Markets Transactions, will fully fund the net purchase price and thereby ensure sufficient liquidity to close the Acquisition.

The accompanying unaudited pro forma consolidated financial statements assume that at closing, the Acquisition will be financed through the net proceeds from the Acquisition Capital Markets Transactions, the Convertible Debentures and cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering). The first instalment of Cdn$728 million relating to the Convertible Debenture offering was paid on closing of the Convertible Debenture offering in 2015 and is reflected in Emera's financial statements as a liability. To the extent (i) Emera raises less than Cdn$6.6 billion in connection with the Acquisition Capital Markets Transactions, or (ii) Emera does not receive payment in full of the Final Instalment of the Convertible Debentures, Emera intends to pay any shortfall by drawing on the Acquisition Credit Facilities and/or using existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) or other sources available to Emera in order to consummate the Acquisition.

The accompanying unaudited pro forma consolidated financial statements: (i) reflect the Acquisition Capital Markets Transactions and applicable issuance and financing costs (see "—Note 3(d): Acquisition Capital Markets Transactions"), and (ii) assume that all cash for the Convertible Debentures has been received and immediately converted into Common Shares at the assumed closing date of the Acquisition (see "—Note 3(c): Common Share Issuance"). Therefore, the accompanying unaudited pro forma consolidated statements of earnings do not recognize any additional interest costs associated with the Convertible Debentures. Interest on the Convertible Debentures is expected to be Cdn$87 million. The accompanying unaudited pro forma financial statements also assume that the Acquisition Credit Facilities and Revolving Facility will not be required to be drawn for closing of the Acquisition.

3. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

(a) Purchase Price and Financing Structure

The following is the estimated net purchase price, estimated net funding requirements and assumed financing structure for the Acquisition. These estimates have been reflected in the accompanying unaudited pro forma consolidated financial statements.

Estimated Net Purchase Price

Unadjusted purchase price	$ 13,779
Estimated acquisition costs (Note 3(e))	130
Estimated net purchase price, before assumed debt	13,909
Assumed debt of TECO Energy	(5,356)
Estimated net purchase price	$ 8,553

Estimated Net Funding Requirements

Estimated net purchase price excluding debt assumed	$ 8,553
Assumed debt of TECO Energy	5,356
Convertible Debenture issuance costs (Note 3(c))	90
Acquisition Capital Markets Transactions issuance costs (Note 3 (d))	118
Estimated net funding requirements	$ 14,117

Assumed Financing Structure

Assumed debt of TECO Energy	$ 5,356
Convertible Debenture issuance (Note 3(c))	2,185
Acquisition Capital Markets Transactions (Note 3(d))	6,576
	$ 14,117

(b) Allocation of estimated net purchase price

The estimated net purchase price has been allocated to the estimated fair values of TECO Energy net assets and liabilities as at March 31, 2016 in accordance with the acquisition method, as follows:

	TECO Energy	Fair Value and Other Adjustments	Net Total
	in millions of Canadian dollars		
Assets Acquired			
Cash and cash equivalents	$ 60	—	$ 60
Receivables, net	311	—	311
Inventory	253	—	253
Regulatory assets	52	—	52
Prepaid expenses	33	—	33
Total Current Assets	709	—	709
Property, plant and equipment	9,797	—	9,797
Regulatory assets	510	—	510
Goodwill	530	(530)	0
Other long-term assets	103	—	103
	$11,649	$(530)	$11,119
Liabilities Assumed			
Short-term debt	$ 665	—	$
Current portion of long-term debt	108	—	108
Accounts payable	475	—	476
Income taxes payable	37	—	37
Derivative instruments	29	—	29
Regulatory liabilities	141	—	141
Pension and post-retirement liabilities	27	—	27
Other current liabilities	75	—	75
Total Current Liabilities	1,557	—	1,558
Long-term debt	4,526	57	4,583
Deferred income taxes	787	—	787
Derivative instruments	1	—	1
Regulatory liabilities	920	—	920

	TECO Energy	Fair Value and Other Adjustments	Net Total
	in millions of Canadian dollars		
Pension and post-retirement liabilities	360	—	360
Other long-term liabilities	147	—	147
	$ 8,299	57	$
Net assets at fair value, as at March 31, 2016			$ 2,763
Estimated net purchase price, before assumed debt and acquisition costs			$ 8 ,423
Goodwill			$ 5,660

TECO Energy is a utility holding company headquartered in Tampa, Florida engaged primarily through its subsidiaries in the regulated vertically- integrated electric utility business in Florida and natural gas transmission and distribution business in Florida and New Mexico. The determination of earnings is based on regulated rates of return that are applied to rate bases and does not change with a change of ownership. "Rate bases" includes jurisdictional rate base, in some cases assets earning a return through clauses and riders, and construction work in progress.

The excess of the estimated net purchase price of the Acquisition, before assumed debt and acquisition costs, over the assumed fair value of net assets acquired from TECO Energy is classified as goodwill on the accompanying unaudited pro forma consolidated balance sheet.

The fair value adjustment on long-term debt relates to non-regulated financing.

(c) Common Share Issuance

In 2015, to finance a portion Acquisition, Emera completed the sale of Cdn$2.185 billion principal amount of 4% convertible unsecured subordinated debentures. These Convertible Debentures were sold on an instalment basis, with one-third paid on closing of the offering, and the remaining payable following satisfaction of conditions precedent to the closing of the Acquisition. For the purposes of these unaudited pro forma consolidated financial statements, the remaining Cdn$1.457 billion relating to the Final Instalment has been received and the Convertible Debentures are assumed to have been fully converted to common shares.

Underwriting costs of Cdn$90 million, of which Cdn$46 million were netted against the proceeds from the first instalment, have been recognized as a deduction from the carrying amount of the equity issued and will result in a corresponding deferred income tax asset of approximately Cdn$28 million based on Emera's Canadian statutory income tax rate of 31%.

Actual interest costs of Cdn$23 million (Cdn$16 million after-tax) in the year ended December 31, 2015 and Cdn$22 million (Cdn$15 million after-tax) in the three months ended March 31, 2016 incurred on the Convertible Debentures have been removed from Interest Expense, Net as a pro forma adjustment as these costs are directly attributed to the Acquisition and are non-recurring in nature (note 3(i)). The remaining Cdn$42 million (Cdn$28 million after-tax) required to be paid on the Convertible Debentures has been recorded as an adjustment to retained earnings as they are directly attributed to the Acquisition and are non-recurring in nature.

(d) Acquisition Capital Markets Transactions

For the purposes of these unaudited pro forma consolidated financial statements, the Acquisition Capital Markets Transactions are assumed to have raised approximately Cdn$6.6 billion for purposes of financing a portion of the Acquisition.

The blended interest rate is estimated at 4.4% which would result in incremental interest for the year ended December 31, 2015 and the three months ended March 31, 2016 of Cdn$284 million and Cdn$76 million, respectively. Incremental interest would result in corresponding deferred income tax benefits of Cdn$103 million and Cdn$28 million, respectively based on Emera's blended U.S. and Canadian income tax rate of 36%.

Estimated issuance costs of Cdn$118 million have been netted against the issuances, and amortized over the term (ten years) of the debt.

(e) Acquisition costs

Acquisition costs are estimated at approximately Cdn$154 million pre-tax (Cdn$130 million after tax) of which Cdn$13 million was incurred in 2015. Acquisition costs include estimated investment banking, accounting, tax, legal, customer benefits negotiated in the settlement to finalize the New Mexico Public Regulation Commission regulatory approval process and other non-financing costs associated with the completion of the Acquisition. These costs have been included as a pro forma adjustment to retained earnings as opposed to being reflected in the unaudited pro forma consolidated statements of earnings of Emera on the basis that these expenses are directly incremental to the Acquisition and are non-recurring in nature.

(f) Income taxes

Income taxes applicable to the pro forma adjustments are calculated at Emera's average tax rates of 31% (Canadian rate) and 39% (U.S. rate).

The deferred income tax asset and liability is the cumulative amount of tax applicable to temporary differences between the accounting and tax values of assets and liabilities. Deferred income tax assets and liabilities are measured at the tax rates expected to apply when these differences reverse. For the purpose of the accompanying unaudited pro forma consolidated financial statements, average deferred income tax rates of 31% (Canadian rate), 39% (U.S. rate) and 36% (blended U.S. and Canadian rate) have been used.

(g) TECO Energy historical shareholders' equity

The historical shareholders' equity of TECO Energy, which includes retained earnings, accumulated other comprehensive income and common shares, is eliminated as a result of the Acquisition.

(h) Earnings per common share

The calculation of the pro forma earnings per Common Share for the year ended December 31, 2015 and for the three months ended March 31, 2016 reflects the assumed issuance of approximately 52.2 million of Common Shares upon conversion of the Convertible Debentures at a net conversion price of Cdn$41.85, as if the issuance had taken place as at January 1, 2015.

(i) Normalizing adjustments for acquisition costs

Mark-to- market pre-tax gains of Cdn$119 million for the year ended December 31, 2015 and pre-tax losses of Cdn$140 million for the three months ended March 31, 2016 (Cdn$101 million after tax gain and Cdn$121 million after tax loss respectively) related to the translation of the Convertible Debenture US$ cash balance and the mark to market adjustments from foreign exchange forward contracts, which are economically hedging the proceeds from the Final Instalment of the Convertible Debentures, have been removed from other income (expenses) as opposed to being reflected in the unaudited pro forma consolidated statements of earnings on the basis that these amounts are directly incremental to the Acquisition and are non-recurring in nature.

Acquisition related costs of Cdn$22 million (Cdn$17 million after tax) incurred by TECO Energy in the year ended December 31, 2015 have been removed from Operating, Maintenance and General Expense as a pro forma adjustment as these costs are directly incremental to the Acquisition and are non-recurring in nature (US$17 million before tax and US$13 million after tax).

Acquisition related costs of Cdn$75 million (Cdn$53 million after tax) incurred by Emera in the year ended December 31, 2015 and Cdn$25 million (Cdn$17 million after tax) incurred in the three months ended March 31, 2016 have been removed from the income statement as a pro forma adjustment as these costs are directly incremental to the Acquisition and are non-recurring in nature. These costs include actual interest on the Convertible Debentures of Cdn$23 million in the year ended December 31, 2015 and Cdn$22 million in the three months ended March 31, 2016 offset by interest earned on the first instalment proceeds of Cdn$1 million, and bridge fees on Acquisition Credit Facilities of Cdn$40 million in the year ended December 31, 2015 and Cdn$4 million for the three months ended March 31, 2016 removed from Interest Expense and Cdn$13 million in acquisition costs incurred in the year ended December 31, 2015 removed from operating, maintenance and general expense.

(j) Foreign exchange translation

The assets and liabilities of TECO Energy, which has a U.S. dollar functional currency, are translated at the exchange rate in effect as at the unaudited pro forma consolidated balance sheet date of March 31, 2016. Revenues and expenses of TECO Energy’s operations are translated at the weighted average exchange rate in effect during the reporting period. The following exchange rates were utilized for the unaudited pro forma consolidated financial statements:

Balance Sheet (U.S. dollars to Canadian dollars)

Month-end rate—March 31, 2016: 1.2971

Income Statement (U.S. dollars to Canadian dollars)

Weighted average rate—January 1, 2015 to December 31, 2015: 1.2788

Weighted average rate—January 1, 2016 to March 31, 2016: 1.3748

Pro Forma Non-U.S. GAAP financial measures

EBITDA and Adjusted EBITDA

The following table presents a reconciliation of EBITDA and Adjusted EBITDA to the most directly comparable U.S. GAAP financial measure, on a historical basis and a pro forma basis, for Emera and EBITDA to the most directly comparable U.S. GAAP financial measure, on a historical basis for TECO Energy, for each of the periods indicated. See "Presentation of Financial Information." The Emera pro forma information for the three months ended March 31, 2016 and the year ended December 31, 2015 set forth below has been prepared using the U.S. dollar to Canadian dollar weighted average rates of 1.3748 (for the period January 1, 2016 to March 31, 2016) and 1.2788 (for the period January 1, 2015 to December 31, 2015), respectively.

	Emera Historical		TECO Energy Historical		Emera Pro Forma	
	Three months ended March 31	Year ended December 31	Three months ended March 31	Year ended December 31	Three months ended March 31	Year ended December 31
	2016	2015	2016	2015	2016	2015
	millions of Canadian dollars		*millions of U.S. dollars*		*millions of Canadian dollars*	
Net Income	$ 54.8	$ 452.4	$ 73.7	$241.2	$243.3	$ 537.5
Add:						
Interest expense, net	75.2	212.6	45.9	186.4	192.1	684.1
Income tax expense (recovery)	26.8	92.4	35.7	155.3	74.7	197.2
Depreciation and amortization	87.5	339.9	89.8	349.0	211	786.2
EBITDA	**$244.3**	**$1,097.3**	**$245.1**	**$931.9**	**$ 721**	**$2,205.1**
Mark-to-market gain (loss), excluding income tax and interest	(75.1)	66.1			64.4	(52.8)
Adjusted EBITDA	**$319.4**	**$1,031.2**			**$656.6**	**$2,257.9**

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis for Three Months Ended March 31, 2016 and the Year Ended December 31, 2015

This Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the first quarter of 2016 relative to the first quarter of 2015; and the full year of 2015 relative to 2014 and 2013; and its financial position as at March 31, 2016 relative to December 31, 2015; and as at December 31, 2015 relative to December 31, 2014. 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 MD&A for the first quarter 2016 and unaudited condensed consolidated interim financial statements and supporting notes as at and for the three months ended March 31, 2016; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2015. Emera follows U.S. GAAP.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. Emera's rate-regulated subsidiaries include:

Emera Rate-Regulated Subsidiary or Investment	Accounting Policies Approved/Examined By
Subsidiary	
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Emera Maine	Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC")
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Dominica Electricity Services Ltd. ("Domlec")	Independent Regulatory Commission, Dominica ("IRCD")
Emera Brunswick Pipeline Company Limited ("EBPC")	Canadian National Energy Board ("NEB")
Investment	
NSP Maritime Link Inc. ("NSPML")	UARB
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline LLC ("M&NP")	NEB and FERC
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities
St. Lucia Electricity Services Limited ("Lucelec")	Government of St. Lucia

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

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

Forward-Looking Information

This MD&A contains "forward-looking information" and statements which reflect the current view with respect to the Company's expectations regarding future growth, results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes within the meaning of Canadian securities laws. All such information and statements are made pursuant to safe harbor provisions contained in applicable securities laws. The words "anticipates," "believes," "could," "estimates," "expects," "intends," "may," "plans," "projects," "schedule," "should," "budget," "forecast," "might," "will," "would," "targets" and similar expressions are often intended to identify forward- looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to Emera's management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations are discussed in the Outlook section of the MD&A and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; the completion of the TECO Energy, Inc. acquisition; uncertainty regarding the length of time required to complete the TECO Energy acquisition; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology could reduce demand for electricity; weather; commodity price risk; construction and development risk; unanticipated maintenance and other expenditures; derivative financial instruments and hedging availability and inability to complete the Convertible Debenture Offering and the financing; failure by the Company to repay the acquisition credit facilities; alternate sources of funding that would be used to replace the acquisition credit facilities may not be available when needed; impact of Acquisition-Related Expenses; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview; followed by the Consolidated Financial Review and Outstanding Common Stock data; then presents information specific to Emera's consolidated subsidiaries and investments:

- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and their parent company, Emera (Caribbean) Incorporated ("ECI"), GBPC, Emera Utility Services (Bahamas) Limited ("EUS Bahamas") and Lucelec;
- Pipelines includes Brunswick Pipeline and M&NP;
- Emera Energy includes Emera Energy Services; Emera Energy Generation which includes Bridgeport Energy, Tiverton Power and Rumford Power ("New England Gas Generating Facilities"), Brooklyn

Power Corporation ("Brooklyn Energy") and Bayside Power Limited Partnership ("Bayside Power"); Bear Swamp; and NWP until its sale on January 29, 2015;

- Corporate and Other includes:
  - Interest revenue on intercompany financings and costs associated with corporate activities that are not directly allocated to the operations of Emera's consolidated subsidiaries and investments;
  - Acquisition costs related to the pending Acquisition;
  - Emera Utility Services Inc. ("Emera Utility Services");
  - Emera Newfoundland & Labrador Holdings Inc. ("ENL") and its investments in NSPML and LIL;
  - Emera Reinsurance Limited;
  - Emera's investment in Algonquin Power & Utilities Corp. ("APUC"); and
  - Other investments.

The Liquidity and Capital Resources, including Consolidated Cash Flow Highlights, Pension Funding, Off-Balance Sheet Arrangements, Outlook, Transactions with Related Parties, Dividends and Payout Ratios, Enterprise Risk and Risk Management, including Financial Instruments, Disclosure and Internal Controls, Critical Accounting Estimates, Changes in Accounting Policies and Practices and Summary of Quarterly Results sections of the MD&A are presented on a consolidated basis.

Introduction and Strategic Overview

Emera Incorporated is a geographically diverse energy and services company that invests in electricity generation, transmission and distribution, gas transmission and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States, and the Caribbean. Emera is targeting eight-per-cent annual dividend growth through 2019.

Regulated utilities are the foundation of Emera's business, providing the Company with strong and consistent earnings. At the core of Emera's utilities strategy is identifying opportunities to invest in the transition from higher-carbon methods of electricity generation to lower-carbon alternatives. NSPI has invested in wind energy, biomass and hydroelectricity and is on track to meet a minimum 40% renewable standard by 2020. In the Caribbean, Emera is similarly focused on introducing cleaner generation alternatives, with an emphasis on affordability and fuel cost stability for its customers.

Emera is investing in electricity transmission to help deliver new renewable energy to market. Emera's ownership in the Maritime Link Project will contribute to the transformation of the electricity market in the Atlantic Provinces, enabling growth in the availability of clean, renewable energy for the region. In addition, the Atlantic Provinces will be connected to the northeastern United States, providing potential for excess renewable energy to be delivered throughout that region.

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

Energy markets worldwide, in particular across North America, are undergoing foundational changes that have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, environmental concerns (including demand for new, less carbon-intensive and renewable generation), lower-cost natural gas, growing demand for new electric heating solutions, and the requirement for large-scale transmission projects to deliver new energy sources to customers. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving the replacement of higher-carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver that energy to market.

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

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

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

Emera targets achieving 75 to 85% of its adjusted income (a non-U.S. GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows that fund dividends, reinvestment and which is reflective of the Company's risk tolerance.

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

Emera has grown its asset base to enable growth and deliver on its strategic objectives. Over the last 10 years, Emera's ability to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. This was demonstrated in Emera's recent issue of convertible debentures represented by instalment receipts in relation to the Acquisition. In addition to access to debt and equity capital markets, cash flow from operations will continue to play a role in financing the Company's future growth. Maintaining strong, investment grade credit ratings is an important component of Emera's financing strategy.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments that do not qualify for hedge accounting or regulatory accounting can have a material impact on the financial results for a specific period. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

Non-U.S. GAAP Financial Measures

Emera uses financial measures that do not have standardized meaning under U.S. GAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-U.S. GAAP measures by adjusting certain U.S. GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period, as detailed below:

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

Adjusted Net Income and Adjusted Earnings per Common Share—Basic

Emera calculates comparable measures by excluding the effect of:

- the mark-to-market adjustments related to Emera's held-for-trading derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp and NWP, until NWP's sale on January 29, 2015;
- the amortization of transportation capacity recognized as a result of certain trading and marketing transactions;
- the mark-to-market adjustments related to an interest rate swap in EBPC; and
- the mark-to-market adjustments included in Emera's other income related to the effect of USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering in connection with the Acquisition.

Management believes excluding from income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows.

Mark-to-market adjustments are further discussed in the Consolidated Financial Highlights section, Emera Energy—Review of 2015, Pipelines—Review of 2015, Corporate and Other—Review of 2015, Emera Energy—Review of 2016, Pipelines—Review of 2016 and Corporate and Other—Review of 2016.

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

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Net income attributable to common shareholders	$ 44.3	$160.1	$397.2	$406.7	$217.5
After-tax mark-to-market gain (loss)	(75.9)	(11.5)	67.2	87.5	(41.9)
Adjusted net income attributable to common shareholders	120.2	171.6	330.0	319.2	259.4
Earnings per common share – basic	0.30	1.10	2.72	2.84	1.64
Adjusted earnings per common share – basic	0.81	1.18	2.26	2.23	1.96

Adjusted Contribution to Consolidated Net Income, Adjusted Income Before Provision for Income Taxes and Adjusted Contribution to Consolidated Earnings per Common Share—Basic

Emera calculates these non-U.S. GAAP measures by excluding the effect of certain mark-to-market adjustments from their respective U.S. GAAP equivalents.

Mark-to-market adjustments are further discussed in "—Consolidated Financial Highlights," "—Emera Energy—Review of 2015," "—Pipelines—Review of 2015," "—Corporate and Other—Review of 2015," "—Emera Energy—Review of 2016," "—Pipelines—Review of 2016 and Corporate and Other—Review of 2016."

Emera EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-U.S. GAAP financial measure used in this Prospectus in respect of Emera. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality.

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

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies, but in management's view appropriately reflects Emera's specific financial condition. These measures are not intended to replace "Net income" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. EBITDA and Adjusted EBITDA are discussed further herein.

The following is a reconciliation of reported net income to EBITDA and Adjusted EBITDA:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
Net income	$54.8	$174.1	$452.4	$452.8	$255.3
Interest expense, net	75.2	44.4	212.6	179.8	172.2
Income tax expense (recovery)	26.8	61.4	92.4	113.6	43.3
Depreciation and amortization	87.5	82.8	339.9	329.0	297.8
EBITDA	244.3	362.7	1,097.3	1,075.2	768.6
Mark-to-market gain (loss), excluding income tax and interest	(75.1)	(21.5)	66.1	128.7	(60.9)
Adjusted EBITDA	$319.4	$384.2	$1,031.2	$946.5	$829.5

TECO Energy EBITDA

EBITDA is a non-U.S. GAAP financial measure used in this Prospectus in respect of TECO Energy. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality.

TECO Energy's EBITDA may not be comparable to the EBITDA measures of other companies, but in TECO Energy's management's view appropriately reflects TECO Energy's specific financial condition. This measures is not intended to replace "Net income" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. TECO Energy's EBITDA is discussed further herein.

The following is a reconciliation of reported net income from continuing operations to EBITDA:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars				
Net income from continuing operations	$ 73.7	$ 63.8	$241.2	$206.4	$188.7
Interest expense, net	45.9	47.9	186.4	171.1	161.4
Income tax expense	35.7	39.9	155.3	138.9	112.6
Depreciation and amortization	89.8	85.5	349.0	315.3	291.8
EBITDA	$245.1	$237.1	$931.9	$831.7	$754.5

Electric Margin

"Electric margin" is a non-U.S. GAAP financial measure used to show the amounts that NSPI, BLPC, GBPC and Domlec retain to recover non-fuel costs. Prudently incurred fuel costs are recovered from customers, except in Domlec, where substantially all fuel costs are passed to customers through the fuel pass-through mechanism. Management believes measuring electric margin shows the portion of the utilities' revenues that directly contribute to Emera's income as distinguished from the portion of revenues that are managed through fuel adjustment mechanisms, which have a minimal impact on income.

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

Electric margin, as calculated by Emera, may not be comparable to the electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. This measure is not intended to replace "Income from operations" which, as determined in accordance with U.S. GAAP, is an indicator of operating performance. Electric margin is discussed further in "NSPI—Electric Margin," "Emera Caribbean—Electric Margin" and "Emera Energy—Adjusted EBITDA".

Significant Items Affecting Earnings

2016

After-Tax Mark-to-Market Losses

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

Acquisition-Related Costs

Emera incurred after-tax costs of Cdn$17.5 million (Cdn$0.12 per common share) in Q1 2016 (2015—nil) related to the Acquisition, including legal, advisory, and financing costs.

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

Sale of Common Shares of APUC

On May 17, 2016, Emera announced that it had agreed to sell all of its 50.1 million common shares of APUC, representing approximately 19.3% of the issued and outstanding common shares, to a syndicate of underwriters at Cdn$10.85 per common share for an aggregate gross amount of approximately Cdn$544 million. The sale was completed on May 24, 2016. Emera intends to use the net proceeds from the sale in support of its general financing requirements, including the Acquisition. Emera continues to hold an equity interest in APUC equivalent to approximately 12.9 million common shares (in the form of subscription receipts and dividend equivalents), which upon conversion represent a continuing common equity interest of approximately 4.75%.

2015

After-Tax Mark-to-Market Gains

After-tax mark-to-market gains increased Cdn$32.3 million to Cdn$105.0 million in Q4 2015 compared to Cdn$72.7 million in Q4 2014; and decreased Cdn$20.3 million to Cdn$67.2 million for the year ended December 31, 2015 compared to Cdn$87.5 million in 2014. The increased mark-to-market gains in the quarter are primarily due to the effect of USD-denominated currency and forward contracts related to the Acquisition. The increase is partially offset by changes in gas and power contract positions and amortization of transportation assets in Emera Energy. In addition, the reversal of 2013 mark-to-market losses in 2014 in Emera Energy is primarily responsible for the year-over-year decrease in after-tax mark to-market gains.

Acquisition-Related Costs

Emera incurred after-tax costs of Cdn$30.3 million (Cdn$0.21 per common share) in Q4 2015 related to its pending Acquisition, including legal, advisory, and financing costs. For the year ended December 31, 2015, TECO Energy acquisition-related costs were Cdn$52.8 million after-tax (Cdn$0.36 per common share). There were no such TECO Energy acquisition-related costs for 2014.

As discussed and included above in "After-Tax Mark-to-Market Gains," the foreign currency earnings effect related to the Convertible Debenture Offering USD cash balance and the forward contracts were recorded as a mark-to-market pre-tax gain of Cdn$118.9 million in "Other income (expenses), net" in Q4 2015.

Further information on the pending Acquisition is in the Developments section of the MD&A.

Gain on Dilution of APUC Equity Investment

In December 2015, APUC closed a 14.355 million common share offering. As a result, Emera recorded a dilution gain of Cdn$11.1 million (after-tax earnings of Cdn$9.4 million or Cdn$0.06 per common share) in "Income from Equity Investments." The gain was a result of APUC's share issuance price being higher than Emera's pre-issuance average book value.

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

BLPC recorded severance costs of Cdn$7.9 million ($6.4 million USD) relating to corporate restructuring, which was recorded in Operating, maintenance and general ("OM&G") in Q2 2015. BLPC sees no requirement to seek regulatory deferral of these costs. The after-tax effect on Emera's Consolidated Net Income in Q2 2015, at Emera's then 80.7% ownership of ECI, was Cdn$5.4 million (Cdn$0.04 per common share).

Sale of Northeast Wind Partnership II, LLC Equity Investment

On January 29, 2015, Emera completed the sale of its 49% interest in NWP for Cdn$282.3 million ($223.3 million USD). This sale resulted in a pre-tax gain of Cdn$18.6 million or Cdn$0.13 per common share (after-tax gain of Cdn$11.5 million or Cdn$0.08 per common share), which was recorded in "Other income (expenses), net" in Q1 2015.

2014

After-Tax Mark-to-Market Gains

After-tax mark-to-market gains (losses) increased Cdn$114.7 million to Cdn$72.7 million in Q4 2014 compared to Cdn$(42.0) million in Q4 2013; and increased Cdn$129.4 million to Cdn$87.5 million for the year ended December 31, 2014 compared to Cdn$(41.9) million in 2013. The increased mark-to-market gains are a result of the reversal of 2013 mark-to-market losses and favourable changes in gas and power contract positions in 2014 at Emera Energy.

Gains on Dilution of APUC Equity Investment

In Q3 2014 and Q4 2014 respectively, APUC closed 16.86 million and 10.05 million common share offerings. In addition, in Q3 2014, an over-allotment option of 2.52 million common shares was exercised. As a result of these two transactions, in Q3 2014, Emera recorded a gain of Cdn$10.8 million (after-tax earnings of Cdn$9.1 million or Cdn$0.06 per common share) and in Q4 2014, a gain of Cdn$7.5 million (after-tax earnings of Cdn$6.4 million or Cdn$0.04 per common share) in "Income from Equity Investments."

Consolidated Financial Review

In Q1 2016, Emera affiliates in the northeastern United States and Atlantic Canada experienced less demand for electricity as a result of unseasonably warm weather. Specifically, NSPI, Emera Maine and Emera Energy's New England Gas Generating Facilities results were affected. Below is a table highlighting significant changes between adjusted net income (a non-U.S. GAAP measure described in "Management's Discussion and Analysis— Non-U.S. GAAP Financial Measures") from Q1 2015 to Q1 2016.

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

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

Consolidated Financial Highlights

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Operating revenues	$ 877.0	$ 888.5	$2,789.3	$2,938.6	$2,230.2
Income from operations	270.0	232.1	507.7	667.3	407.1
Net income attributable to common shareholders	44.3	160.1	397.2	406.7	217.5
After-tax mark-to-market gain (loss)	(75.9)	(11.5)	67.2	87.5	(41.9)
Adjusted net income attributable to common shareholders	120.2	171.6	330.0	319.2	259.4
Earnings per common share – basic	0.30	1.10	2.72	2.84	1.64
Earnings per common share – diluted	0.30	1.09	2.71	2.82	1.64
Adjusted earnings per common share – basic	0.81	1.18	2.26	2.23	1.96
Dividends per common share declared	0.4750	0.3875	1.6625	1.4750	1.4125
Adjusted EBITDA	$ 319.4	$ 384.2	$1,031.2	$ 946.5	$ 829.5

Operating Unit Contributions to Adjusted Net Income

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
NSPI	$ 52.5	$ 68.0	$129.9	$124.9	$126.0
Emera Maine	9.3	11.5	45.1	42.4	38.4
Emera Caribbean	9.8	8.8	40.5	28.7	33.4
Pipelines	9.7	9.9	39.6	32.7	30.3
Emera Energy	47.9	76.4	130.1	98.2	45.1
Corporate and Other	(9.0)	(3.0)	(55.2)	(7.7)	(13.8)
Adjusted net income attributable to common shareholders	120.2	171.6	330.0	319.2	259.4
After-tax mark-to-market gain (loss)	(75.9)	(11.5)	67.2	87.5	(41.9)
Net income attributable to common shareholders	$ 44.3	$160.1	$397.2	$406.7	$217.5

	Three months ended March		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
Operating cash flow before changes in working capital	$ 232.4	$ 257.5	$ 775.8	$ 716.3	$ 574.3
Change in working capital	(51.8)	(137.9)	(101.6)	46.2	(10.1)
Operating cash flow	180.6	$ 119.6	674.2	762.5	564.2
Investing cash flow	(139.3)	$ 195.9	(123.7)	(710.9)	(921.6)
Financing cash flow	$ (45.8)	$(259.3)	$ 221.1	$ 58.2	$ 362.1

	Three months ended March 31, 2016	Year ended December 31		
		2015	2014	2013
	millions of Canadian dollars			
Working capital(1)	$ 580.3	$ 599.2	$ 358.3	$ 372.7
Total assets(1)	11,448.6	12,012.3	9,853.4	8,876.8
Total long-term liabilities(1)	$ 5,492.1	$ 5,580.7	$5,025.1	$4,449.7

(1) These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

Review of 2015

Emera Consolidated Statements of Income

	Three months ended December 31		Year ended December 31		
	2015	2014	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Operating revenues – regulated	$533.8	$526.7	$2,192.9	$2,113.1	$2,040.8
Operating revenues – non-regulated	197.8	256.0	596.4	825.5	189.4
Total operating revenues	731.6	782.7	2,789.3	2,938.6	2,230.2
Regulated fuel for generation and purchased power	199.9	212.9	814.5	844.3	868.4
Regulated fuel adjustment mechanism and fixed cost deferrals	10.3	5.7	41.6	46.6	(40.8)
Non-regulated fuel for generation and purchased power	90.7	78.2	335.7	401.1	89.8
Non-regulated direct costs	4.4	9.7	19.5	31.3	52.4
Operating, maintenance and general	173.6	144.0	666.8	560.8	505.0
Provincial, state and municipal taxes	15.8	14.8	63.6	58.2	50.5
Depreciation and amortization	87.9	82.0	339.9	329.0	297.8
Total operating expenses	582.6	547.3	2,281.6	2,271.3	1,823.1
Income from operations	149.0	235.4	507.7	667.3	407.1
Income from equity investments	26.4	15.4	108.6	66.6	38.1
Other income (expenses), net	114.8	2.9	141.1	12.3	25.6
Interest expense, net	70.9	44.7	212.6	179.8	172.2
Income before provision for income taxes	219.3	209.0	544.8	566.4	298.6
Income tax expense (recovery)	20.7	53.7	92.4	113.6	43.3
Net income	198.6	155.3	452.4	452.8	255.3
Non-controlling interest in subsidiaries	6.5	4.1	24.9	19.9	18.5
Net income of Emera Incorporated	192.1	151.2	427.5	432.9	236.8
Preferred stock dividends	—	—	30.3	26.2	19.3
Net income attributable to common shareholders	192.1	151.2	397.2	406.7	217.5
After-tax mark-to-market gain (loss)	105.0	72.7	67.2	87.5	(41.9)
Adjusted net income attributable to common shareholders(1)	87.1	78.5	330.0	319.2	259.4
Earnings per common share – basic	1.31	1.05	2.72	2.84	1.64
Earnings per common share – diluted	1.30	1.02	2.71	2.82	1.64
Adjusted earnings per common share – basic(1)	$ 0.59	$ 0.54	$ 2.26	$ 2.23	$ 1.96

(1) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures".

Emera Incorporated's consolidated net income attributable to common shareholders increased Cdn$40.9 million to Cdn$192.1 million in Q4 2015 compared to Cdn$151.2 million for the same period in 2014. For the year ended December 31, 2015, Emera's consolidated net income attributable to common shareholders decreased Cdn$9.5 million to Cdn$397.2 million compared to Cdn$406.7 million in 2014.

Consolidated Income Statement Highlights for Q1 2016 and Q4 2015

Operational Results

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

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

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

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

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

Income from operations decreased Cdn$86.4 million to Cdn$149.0 million in Q4 2015 compared to Cdn$235.4 million in the same quarter in 2014 primarily due to negative mark-to-market changes of Cdn$101.2 million and Cdn$21.0 million in costs related to the pending Acquisition. These decreases were partially offset by Emera Energy's increased trading and marketing margin, and increased margin at the New England Gas Generation Facilities.

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

Total operating revenues decreased 6.5% to Cdn$731.6 million in Q4 2015 compared to Cdn$782.7 million in Q4 2014 primarily due to:

- Cdn$113.7 million decrease from changes in mark-to-market impacts;
- Cdn$46.0 million increase at the New England Gas Generation Facilities primarily due to major outage work at Bridgeport Energy in 2014 and the effect of a strengthening USD;
- Cdn$22.2 million increase in Emera Energy Services reflecting growth in the volume of business and increased investment in transportation capacity;
- Cdn$9.5 million decrease at BLPC primarily due to lower fuel revenue reflecting lower fuel prices;
- Cdn$6.9 million increase at Emera Maine primarily due to the effect of a strengthening USD, partially offset by decreased sales volumes;
- Cdn$5.8 million increase at NSPI as a result of recovery of prior years' fuel costs from a 2014 UARB settlement agreement, partially offset by decreased sales volumes due to weather.

Total operating expenses increased 6.4% to Cdn$582.6 million in Q4 2015 compared to Cdn$547.3 million in Q4 2014, primarily due to the effect of a strengthening USD, acquisition costs related to the Acquisition, and increased fuel costs at the New England Gas Generation Facilities reflecting major outage work at Bridgeport Energy in 2014, partially offset by lower fuel prices at BLPC and changes in mark-to-market impacts.

Income from equity investments

Income from equity investments increased 71.4% in Q4 2015 to Cdn$26.4 million compared to Cdn$15.4 million in the same period in 2014, primarily due to higher APUC earnings in 2015 and a higher pre-tax gain on dilution of Emera's APUC investment in 2015.

Other income (expenses), net

Other income decreased Cdn$161.1 million to Cdn$(139.2) million in Q1 2016 compared to Cdn$21.9 million in Q1 2015. This was primarily due to mark-to-market losses relating to the effect of USD-denominated currency and forward contracts put into place to economically hedge anticipated proceeds from the Convertible Debenture Offering and the 2015 gain on the sale of NWP.

Other income increased Cdn$111.9 million to Cdn$114.8 million in Q4 2015 compared to Cdn$2.9 million in the same period in 2014. This was primarily due to mark-to-market gains on USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering for the Acquisition.

Interest expense, net

Interest expense increased Cdn$30.8 million to Cdn$75.2 million in Q1 2016 compared to Cdn$44.4 million in Q1 2015 primarily due to interest on Convertible Debentures represented by instalment receipts related to the pending Acquisition.

Income tax expense (recovery)

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

Income tax expense decreased Cdn$33.0 million to Cdn$20.7 million in Q4 2015 compared to Cdn$53.7 million for the same period in 2014 primarily due to decreased income before provision for income taxes including mark-to-market adjustments related to Emera Energy, changes in the proportion of Emera Energy income earned in higher tax rate foreign jurisdictions, and a legislated change by the Province of Nova Scotia to the deferred tax treatment of two wind farms at NSPI. These decreases were partially offset by the taxable portion of mark-to-market gains relating to the effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering for the Acquisition.

Consolidated Income Statement Highlights for 2015

Operational Results

Income from operations decreased Cdn$159.6 million to Cdn$507.7 million for the year ended December 31, 2015 compared to Cdn$667.3 million in 2014 primarily due to mark-to-market changes of Cdn$189.2 million. Increased margin at the New England Gas Generation Facilities, the effect of the strengthening USD, and increased operating income at NSPI, partially offset by Cdn$51.5 million in expenses relating to the pending Acquisition and Emera Energy's decreased trading and marketing margin.

Total operating revenues decreased 5.1% to Cdn$2,789.3 million for the year ended December 31, 2015 compared to Cdn$2,938.6 million in the same period in 2014 primarily due to:

- Cdn$203.7 million decrease from changes in mark-to-market impacts
- Cdn$47.3 million decrease at BLPC primarily due to lower fuel revenue reflecting lower fuel prices

- Cdn$32.6 million decrease in Emera Energy Services reflecting a return to more normal market circumstances following particularly strong market conditions in the northern United States and Ontario in Q1 2014
- Cdn$69.1 million increase at NSPI as a result of recovery of prior years' fuel costs from the 2014 UARB settlement agreement and higher sales volumes, primarily due to weather
- Cdn$46.3 million increase at the New England Gas Generation Facilities primarily due to higher realized margins, increased generation largely because Bridgeport Energy had a major planned outage in Q4 2014, and the effect of a strengthening USD
- Cdn$41.6 million increase at Emera Maine primarily due to the effect of a strengthening USD, partially offset by decreased sales volumes.

Total operating expenses increased 0.5% to Cdn$2,281.6 million for the year ended December 31, 2015 compared to Cdn$2,271.3 million in 2014. This was primarily due to the effect of a strengthening USD, acquisition costs related to the Acquisition and increased regulated fuel for generation and purchased power at NSPI, partially offset by decreased fuel costs at the New England Gas Generation Facilities and BLPC reflecting lower fuel prices and changes in mark-to-market impacts.

Income from equity investments

Income from equity investments increased Cdn$42.0 million to Cdn$108.6 million for the year ended December 31, 2015 compared to $66.6 million in the same period of 2014. This was primarily due to favourable mark-to-market changes of Cdn$7.7 million, NWP losses in 2014, higher APUC equity earnings, increased allowance for funds used during construction ("AFUDC") earnings by NSPML, and increased earnings resulting from the increased investment in LIL, partially offset by lower APUC dilution gains in 2015 compared to 2014.

Other income (expenses), net

Other income increased Cdn$128.8 million to Cdn$141.1 million for the year ended December 31, 2015 compared to Cdn$12.3 million in the same period in 2014. This was primarily due to a mark-to-market gains relating to the foreign exchange effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering for the Acquisition and the gain on the sale of NWP.

Income tax expense (recovery)

Income tax expense decreased Cdn$21.2 million to Cdn$92.4 million for the year ended December 31, 2015 compared to Cdn$113.6 million in 2014. This was primarily due to decreased income before provision for income taxes, including mark-to-market adjustments related to Emera Energy, partially offset by the taxable portion of mark-to-market gains relating to the effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering financing the Acquisition.

Consolidated Operating Cash Flow Highlights for Q1 2015 and Q1 2016

Operating Activities

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

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

Net cash provided by operating activities decreased Cdn$88.3 million to Cdn$674.2 million for the twelve months ended December 31, 2015 compared to Cdn$762.5 million for the same period in 2014. Cash from operations before changes in working capital increased by Cdn$62.0 million primarily due to higher margins at the New England Gas Generation Facilities, the effect of a strengthening USD and increased Fuel Electric Revenues at NSPI, partially offset by lower trading and marketing margin at Emera Energy Services, payment of acquisition costs related to the Acquisition and the deferral of demand side management ("DSM") program costs at NSPI.

Changes in working capital decreased operating cash flows by Cdn$150.3 million primarily due to increased receivables reflecting higher posted margin at Emera Energy and increased revenues at NSPI and increased dividends payable, partially offset by favourable changes in fuel inventory at NSPI reflecting increased consumption.

Effect of Foreign Currency Translation

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

	Q1 2016 vs Q1 2015	Q1 2015 vs Q1 2014
	millions of Canadian dollars (except per share amounts)	
Impact on income from continuing operations		
Total operating revenues	$48.5	$43.3
Total operating expenses	(25.7)	(32.5)
Net income	15.8	9.2
Adjusted net income[(1)]	7.2	11.0
Impact on earnings per share		
Basic	$0.11	$0.06
Basic – adjusted	$0.05	$0.08

	Q4 2015 vs Q4 2014	Q4 2014 vs Q4 2013
	millions of Canadian dollars (except per share amounts)	
Impact on income from continuing operations		
Total operating revenues	$49.1	$30.7
Total operating expenses	(42.3)	(15.6)
Net income	4.0	10.4
Adjusted net income[(1)]	7.0	2.4
Impact on earnings per share		
Basic	0.03	0.7
Adjusted	$0.05	$0.02

	2015 vs 2014	2014 vs 2013
	millions of Canadian dollars (except per share amounts)	
Impact on income from continuing operations		
Total operating revenues	$ 163.6	$ 98.6
Total operating expenses	(139.4)	(67.0)
Net income	19.2	22.0
Adjusted net income[(1)]	26.0	12.1
Impact on earnings per share		
Basic	0.13	0.15
Adjusted	$ 0.18	$ 0.08

(1) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures."

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

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

	Year ended December 31		
Average equivalent of $1.00 USD	**2015**	**2014**	**2013**
CAD	$1.26	$1.12	$1.03

Consolidated Balance Sheets Highlights

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	$ (73.9)	Decreased primarily due to the impact of a stronger CAD
Receivables, net	32.9	Increased due to seasonal trends of business at NSPI and Emera Energy
Inventory	(53.5)	Decreased primarily due to lower fuel inventory volumes as a result of consumption and lower commodity pricing at NSPI
Derivative instruments (current and long-term)	(239.3)	Decreased primarily due to the effect of a stronger CAD and settlements of derivative instruments at Emera Energy and NSPI
Prepaid expenses	22.1	Increased primarily due to timing of provincial grants in lieu of taxes and insurance payments at NSPI
Property, plant and equipment, net of accumulated depreciation	(173.1)	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and depreciation, offset by additions
Investments subject to significant influence	64.4	Increased primarily due to increased investments in LIL and NSPML
Other assets (current and long-term)	(70.2)	Decreased primarily due to the amortization of transportation/storage capacity assets at Emera Energy
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	(27.5)	Decreased primarily due to the effect of a stronger CAD on debt held by foreign subsidiaries
Accounts payable	(22.7)	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries

millions of Canadian dollars	Increase (Decrease)	Explanation
Derivative instruments (current and long-term)	(218.2)	Decreased primarily due to settlements of natural gas and power contracts at Emera Energy
Regulatory liabilities (current and long-term)	(74.4)	Decreased primarily due to changes in regulated derivatives partially offset by an increased FAM regulatory liability at NSPI
Other liabilities (current and long-term)	(47.8)	Decreased primarily due to the effect of a stronger CAD on the Bear Swamp investment, payment of restructuring costs at Emera Caribbean and timing of accruals
Common stock	41.5	Increased primarily due to issuance of common stock for the dividend reinvestment program
Accumulated other comprehensive income	(130.7)	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries
Retained earnings	(25.7)	Decreased due to dividends payments in excess of net income
Non-controlling interest in subsidiaries	(28.8)	Decreased due to increased ownership by Emera in ECI

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	$852.3	Increased from proceeds of the convertible debentures and long-term debt and cash from operations, partially offset by increased debt levels, preferred shares repayments and dividends
Receivables, net	63.9	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and increased cash collateral position on derivative instrument at NSPI
Income taxes receivable, net of income taxes payable (current and long-term)	52.8	Increased primarily due to the payment of taxes owing for the 2014 tax year by Emera Energy Services and NSPI's required prepayment of taxes for reassessments relating to the timing of tax deductions under dispute with the Canada Revenue Agency
Derivative instruments (current and long-term)	188.6	Increased primarily due to favourable changes in USD price positions, partially offset by settlements of derivative instruments at NSPI and Emera Energy
Regulatory assets (current and long- term)	96.8	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and increased regulatory assets related to deferred income taxes, DSM and regulated derivatives, partially offset by amortization at NSPI
Property, plant and equipment, net of accumulated depreciation	577.8	Increased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries, increased capital expenditures resulting from major planned outage work at Bridgeport Energy, funding of capital investments at Tiverton Power for 2016 major outage work and increased capital spending at NSPI, partially offset by depreciation

millions of Canadian dollars	Increase (Decrease)	Explanation
Investments subject to significant influence	117.7	Increased primarily due to reclassification of Bear Swamp investment credit balance to Other Long-Term Liabilities, outstanding APUC subscription receipts which became eligible for conversion in Q4 2015 (originally recorded in Other Assets), dilution gains in APUC, and increased investments in LIL and M&NP, partially offset by the sale of NWP
Available-for-sale investments	31.6	Increased primarily due to investment by Emera Reinsurance Limited and favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries
Goodwill	42.6	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries
Intangibles	57.6	Increased primarily due to investment by Emera Maine in a customer information system and the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries
Other assets (current and long-term)	115.2	Increased primarily due to increase in transportation capacity assets in Emera Energy and increased deferred financing costs related to the pending Acquisition, offset by a decrease in APUC subscription receipts which became eligible for conversion in Q4 2015 (now recorded as Investments Subject to Significant Influence)
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	28.3	Increased primarily due to increased debt levels at NSPI to fund the redemption of preferred stock, issuance of long-term debt by EBPC and the effect of a stronger USD on debt held by foreign subsidiaries, partially offset by repayment of long-term debt
Convertible debentures represented by instalment receipts	727.6	Increased due to the issuance of convertible debentures related to the pending Acquisition
Deferred income tax liabilities, net of deferred income tax assets	174.0	Increased primarily due to the utilization of non-capital loss carryforwards and accelerated tax deductions related to property, plant and equipment at NSPI and Emera Maine
Derivative instruments (current and long-term)	240.5	Increased primarily due to a new asset management agreement and unfavourable changes in commodity pricing at Emera Energy and unfavourable mark-to-market impacts relating to interest rate and foreign exchange hedges at EBPC
Regulatory liabilities (current and long- term)	168.7	Increased primarily due to changes in derivative instruments as a result of favourable USD price positions and increased FAM liability at NSPI, partially offset by settlements of derivative instruments at NSPI

millions of Canadian dollars	Increase (Decrease)	Explanation
Pension and post-retirement liabilities (current and long-term)	(57.8)	Decreased primarily due to improvement in funded position as a result of greater than expected asset return at NSPI
Other liabilities (current and long-term)	267.7	Increased primarily due to deferred cost impact of parts and capital work delivered for performance in 2015 by a service provider under long-term service agreements at the New England Gas Generation Facilities, and reclassification of Bear Swamp investment credit balance from Investments Subject to Significant Influence
Common stock	141.1	Increased primarily due to issuance of common stock for the dividend reinvestment program and purchase of additional ECI shares
Accumulated other comprehensive loss	(484.1)	Decreased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries and the amortization of unrecognized pension and post-retirement benefit costs at NSPI
Retained earnings	156.1	Increased due to net income in excess of dividends paid
Non-controlling interest in subsidiaries	(172.7)	Decreased due to increased ownership in ECI

Recent Developments

Emera

Sale of Common Shares of APUC

On May 17, 2016, Emera announced that it had agreed to sell all of its 50.1 million common shares of APUC, representing approximately 19.3% of the issued and outstanding common shares, to a syndicate of underwriters at Cdn$10.85 per common share for an aggregate gross amount of approximately Cdn$544 million. The sale was completed on May 24, 2016. Emera intends to use the net proceeds from the sale in support of its general financing requirements, including the Acquisition. Emera continues to hold an equity interest in APUC equivalent to approximately 12.9 million common shares (in the form of subscription receipts and dividend equivalents), which upon conversion represent a continuing common equity interest of approximately 4.75%.

Pending Acquisition of TECO Energy

On September 4, 2015, the Company announced a definitive agreement for Emera to acquire TECO Energy (NYSE:TE) (the "Acquisition"). TECO Energy shareholders will receive $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.6 billion USD and which includes the assumption of approximately $4.1 billion USD of debt.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy's holdings include: Tampa Electric, an integrated regulated electric utility which serves nearly 725,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves nearly 365,000 customers across Florida; and NMGC, a regulated gas distribution utility which serves more than 520,000 customers across New Mexico.

The Acquisition is expected to close mid-2016. Closing of the pending acquisition remains subject to approval by the NMPRC, and the satisfaction of customary closing conditions.

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

The Stipulation Agreement sets out a number of Emera's commitments including honouring commitments made by TECO Energy in its 2014 acquisition case, investing in the expansion of the natural gas system to underserved communities and the Mexican border, and providing resources to support certain economic growth projects and programs. The Stipulation Agreement is subject to review and approval by the NMPRC. In May, 2016 the hearing examiner held a hearing in connection with the joint application to the NMPRC of the change in control of NMGC affected by the Acquisition. A final order of the NMPRC is expected in mid-2016.

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

ECI Amalgamation

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

To effect the amalgamation, all issued and outstanding common shares of ECI were converted to Class A redeemable preferred shares. In Q1 2016, the Class A redeemable preferred shares of ECI not owned were redeemed. Minority ECI shareholders could elect to receive Cdn$23.26 ($33.30 BBD) in cash per common share ("Cash Offer") or 2.1 Depositary Receipts ("DR") per common share, with each DR representing one quarter of a common share of Emera ("DR Offer"); or a combination of the two offers. The total consideration paid to redeem the minority interest was Cdn$15.3 million ($23.4 million BBD), consisting of Cdn$14.4 million of the Cash Offer ($22.0 million BBD) and Cdn$0.9 million of the DR Offer ($1.4 million BBD). The amalgamated entity retained the name Emera (Caribbean) Incorporated.

Convertible Debentures Represented By Instalment Receipts

To finance a portion of the pending Acquisition, Emera, through a direct wholly owned subsidiary (the "Selling Debentureholder"), on September 28, 2015, completed the sale of Cdn$1.9 billion of aggregate principal amount of 4.0% convertible unsecured subordinated debentures, represented by instalment receipts (the "Convertible Debenture Offering").

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

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

Prior to the Final Instalment Date, the Convertible Debentures are represented by instalment receipts. The instalment receipts began trading on the Toronto Stock Exchange ("TSX") on September 28, 2015 under the symbol "EMA.IR." The Convertible Debentures will not be listed. The Convertible Debentures will mature on September 29, 2025 and bear interest at an annual rate of 4% per Cdn$1,000 principal amount of Convertible Debentures until and including the Final Instalment Date, after which the interest rate will be 0%. Based on the first instalment of Cdn$333 per Cdn$1,000 principal amount of Convertible Debentures, the effective annual yield to and including the Final Instalment Date is 12%, and the effective annual yield thereafter is 0%.

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

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

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

At maturity, Emera will repay the principal amount of any Convertible Debentures not converted and remaining outstanding in cash. Emera has the right to satisfy the obligation to repay the principal amount due in common shares, which will be valued at 95% of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment and the overallotment of the Convertible Debenture Offering were Cdn$727.6 million, or Cdn$681.4 million net of issue costs, and are held and invested in short-term USD investment grade securities. The Convertible Debentures represented by instalment receipts are classified as a current liability on the Consolidated Balance Sheets as the pending Acquisition is expected to close in fiscal 2016. The mark-to-market effect related to the translation of the U.S. foreign currency to Canadian currency is recorded in income, but not reflected in adjusted net income.

The net proceeds of the final instalment payment of the Convertible Debenture Offering are expected to be, in aggregate, approximately Cdn$1.4 billion and will be used, together with the net proceeds of the first instalment payment, to finance, directly or indirectly, the Acquisition and other Acquisition-Related Expenses. To mitigate the foreign currency translation risk associated with the final instalment Emera entered into USD denominated forward contracts, which are recorded on the Consolidated Balance Sheets. The mark-to-market effect on these hedges is reported in the income statement and impacts income, but is not reflected in adjusted income.

Approximately Cdn$22.1 million (Cdn$15.2 million after-tax) in interest expense associated with the Convertible Debentures was recognized in Q4 2015 and Cdn$22.7 million (Cdn$15.7 million after-tax) was incurred during fiscal 2015 (2014 – nil).

Increase in Common Dividend

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

Maritime Link Project

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

On April 9, 2015, NSPML and the Assembly of Nova Scotia Mi'kmaq Chiefs signed a Socio-Economic Agreement for the Maritime Link Project. Under this agreement, NSPML will support ongoing engagement and commitments made during the Environmental Assessment process, including Mi'kmaq participation in environmental monitoring and employment and business opportunities for Mi'kmaq people.

Emera Maine

Return on Equity ("ROE") Complaints

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

Recent Financing Activity

Emera

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

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

NSPI

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

NSPI Series I Cdn$70 million 8.40% medium-term notes ("MTN") matured on October 23, 2015 and were repaid.

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

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

EBPC

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

Emera Energy

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at a fixed rate of 4.89%, and $25 million USD at a floating rate of LIBOR plus 2.70%. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a Cdn$178.7 million ($137.3 million USD) non-taxable distribution in Q4 2015.

Appointments

Executive

On January 15, 2016, Greg Blunden was appointed Chief Financial Officer ("CFO") of Emera, effective March 1, 2016. Mr. Blunden has held financial leadership roles at Emera, Emera Maine and NSPI. Most recently, Mr. Blunden was Vice President, Corporate Strategy & Planning.

On January 15, 2016, Emera's current CFO, Scott Balfour, was appointed Chief Operating Officer, Northeast and Caribbean, effective March 1, 2016. Mr. Balfour will provide senior executive leadership for Emera's existing operations, including NSPI, Emera Energy, Emera Maine, Emera Caribbean, EBPC and Emera Utility Services.

On January 15, 2016, Wayne O'Connor was appointed Vice President, Corporate Strategy & Planning for Emera, effective March 1, 2016. Mr. O'Connor will coordinate Emera's planning and strategy development efforts to grow and expand the Company's business. Previously, he was Executive Vice- President of Operations at NSPI.

On September 22, 2015, Rob Bennett was appointed President and Chief Executive Officer of Merger Sub, to lead the integration of TECO Energy. Previously, Mr. Bennett had been the Chief Operating Officer, Eastern Canada.

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

Outstanding Common Stock Data

Common stock issued and outstanding:	Millions of shares	Millions of Canadian dollars
December 31, 2014	143.78	$2,016.4
Issuance of common stock(1)	1.25	53.7
Issued for cash under Purchase Plans at market rate	2.10	88.3
Discount on shares purchased under Dividend Reinvestment Plan	—	(4.1)
Options exercised under senior management stock option plan	0.08	2.3
Employee Share Purchase Plan	—	0.9
December 31, 2015	147.21	$2,157.5
Issuance of common stock(1)	0.06	2.7
Issued for cash under Purchase Plans at market rate	0.58	26.2
Discount on shares purchased under Dividend Reinvestment Plan	—	(1.2)
Options exercised under senior management stock option plan	0.50	13.6
Employee Share Purchase Plan	—	0.2
March 31, 2016	148.35	$2,199.0

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

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

The weighted average shares of common stock outstanding—basic, which includes both issued, outstanding common stock and outstanding deferred share units, for the three months ended March 31, 2016 was 148.7 million (2015 – 144.9 million).

NSPI

Overview

NSPI was created in 1992 through the privatization of the Crown corporation Nova Scotia Power Corporation (“NSPC”). NSPI is a fully-integrated regulated electric utility and is the primary electricity supplier in Nova Scotia, Canada. NSPI has Cdn$4.6 billion of assets and provides electricity generation, transmission and distribution services to approximately 507,000 customers. NSPI owns 2,483 MW of generating capacity, of which approximately 50% is coal-fired; 28% of which is natural gas and/or oil; 19% of which is hydro and wind and 3% of which is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers (“IPP”). These IPPs own and operate 496 MW of wind and biomass fueled generation capacity, which will increase to 552 MW in 2016. NSPI also owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities. NSPI has a workforce of approximately 1,700 people.

NSPI is a public utility as defined in the Public Utilities Act and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI’s operations and expenditures. Electricity rates for NSPI’s customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time at its request or at the UARB’s request.

NSPI is regulated under a cost-of-service model, with rates established to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. NSPI's target regulated return on equity range is currently 8.75% to 9.25%, based on an actual five-quarter average regulated common equity component of up to 40.0%.

NSPI has a fuel adjustment mechanism ("FAM"), approved by the UARB, allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between prudently incurred fuel for generation and purchased power and certain fuel-related costs ("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.

A settlement agreement, approved by the UARB in November 2014, resulted in approximately Cdn$56.0 million of the outstanding FAM regulatory asset balance from the prior year being collected in 2015. Residential customers did not experience a rate increase in 2015, as the FAM recovery of approximately Cdn$56.0 million was offset with the removal of charges previously included in NSPI billings. The charges were on behalf of Efficiency Nova Scotia, a program run by the Province of Nova Scotia and regulated by the UARB. Certain industrial customer classes experienced rate increases of approximately 1.5% in 2015.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates reset the base cost of fuel rate for 2016 and seek to recover Cdn$13.7 million of prior years' unrecovered Fuel Costs in 2016. This results in a combined rate decrease for customers of approximately 1%.

In December 2015, the Electricity Plan Implementation (2015) Act (the "Electricity Plan Act") was enacted by the Province of Nova Scotia. Further information is included in the "—Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals" section.

Although the market in Nova Scotia is otherwise mature, the transformation of energy supply to lower emission sources has driven organic growth within NSPI as new investments have been made in renewable generation and system reliability projects.

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix. The most recent target, for years 2015 through 2019, is 25% of electrical energy which will be derived from renewable sources. This target was met for 2015, with 27% of NSPI's generation mix derived from renewable sources. In 2020, the target is 40% of electrical energy to be derived from renewable sources.

Review of 2016 and 2015

NSPI Net Income

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Operating revenues – regulated	$397.5	$446.5	$1,417.3	$1,348.2	$1,334.9
Regulated fuel for generation and purchased power[1]	141.5	189.4	542.8	511.7	556.9
Regulated fuel adjustment mechanism and fixed cost deferrals	17.6	(7.2)	41.6	46.6	(40.8)
Operating, maintenance and general	87.4	79.6	298.1	273.6	272.3
Provincial grants and taxes	9.7	9.6	38.5	38.3	37.7
Depreciation and amortization	48.4	51.5	206.5	204.0	213.8
Total operating expenses	304.6	322.9	1,127.5	1,074.2	1,039.9
Income from operations	92.9	123.6	289.8	274.0	295.0
Other expenses net[2]	1.3	3.8	5.7	5.0	7.1
Interest expense, net	31.0	28.8	122.1	116.5	119.6
Income before provision for income taxes	60.6	91.0	162.0	152.5	168.3
Income tax expense (recovery)	8.1	21.0	23.4	19.7	34.4
Net income of Nova Scotia Power Inc.	52.5	70.0	138.6	132.8	133.9
Preferred stock dividends[3]	—	2.0	8.7	7.9	7.9
Contribution to consolidated net income	52.5	68.0	129.9	124.9	126.0
Contribution to consolidated earnings per common share	0.35	0.47	0.89	0.87	0.95
EBITDA[4]	$140.0	$171.3	$ 490.6	$ 473.0	$ 501.7

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

(2) Other expenses, net is included in "Other income (expenses), net" on the Consolidated Statements of Income.

(3) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Consolidated Statements of Income. In Q4 2015, NSPI redeemed its preferred shares.

(4) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures."

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

Highlights of the changes are summarized in the following table:

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

NSPI's contribution to consolidated net income increased Cdn$10.0 million to Cdn$40.1 million in Q4 2015 compared to Cdn$30.1 million in Q4 2014. For the year ended December 31, 2015, NSPI's contribution to consolidated net income increased Cdn$5.0 million to Cdn$129.9 million in 2015 compared to Cdn$124.9 million in 2014.

Highlights of the changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Contribution to consolidated net income–2013		$126.0
Increased electric margin primarily due to increased non-fuel electric revenues across all customers groups as a result of increased electricity pricing, partially offset by the FAM audit disallowance		15.8
Decreased fixed cost deferrals primarily due to an increase in the non-fuel revenues and lower depreciation and amortization		(43.2)
Decreased depreciation and amortization primarily due to reductions in regulatory amortization (see Regulatory Amortization section below for explanation)		9.8
Decreased interest expense, net primarily due to lower levels of long-term debt		3.1
Decreased income tax expense primarily due to increased tax deductions related to higher pension contributions for 2014, decreased income before provision for income taxes and decreased non-deductible regulatory amortization, partially offset by a non-recurring change in unrecognized tax benefits in 2013 due to the enactment of tax legislation related to preferred stock dividends		14.7
Other, net[(1)]		(1.3)
Contribution to consolidated net income–2014	$30.1	$124.9
Increased electric margin (see Electric Margin section below for explanation)	0.5	13.0
Increased fixed cost deferrals year-over-year primarily due to the new DSM regulatory deferral commencing in 2015, partially offset by an increase in the amount of non-fuel revenues deferred compared to 2014	(1.7)	30.5
Decreased OM&G expenses quarter-over-quarter primarily due to non-recurring 2014 expenses and increased overhead credits on capital projects, partially offset by higher pension and DSM costs; year-over-year increase is primarily due to increased DSM program costs as a results of legislation, effective January 1, 2015, requiring NSPI to purchase electricity efficiency and conservation activities and higher pension costs, partially offset by lower storm costs	2.7	(24.5)
Increased interest expense, net primarily due to lower interest revenues related to FAM and fixed cost deferrals and higher debt levels	(1.4)	(5.6)
Decreased income tax expense quarter-over-quarter primarily due to a legislated change by the Province of Nova Scotia to the deferred tax treatment of South Canoe and Sable wind farms resulting in prior period deferred income taxes being recorded as regulatory assets in Q4 2015; year-over-year increase primarily due to increased income before provision for income taxes	11.9	(3.7)
Other, net[(1)]	(2.0)	(4.7)
Contribution to consolidated net income–2015	$40.1	$129.9

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

Operating Revenues—Regulated

NSPI's Operating Revenues—regulated include sales of electricity and other services as summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars				
Electric revenues	$391.7	$440.0	$1,389.1	$1,319.2	$1,304.3
Other revenues	5.8	6.5	28.2	29.0	30.6
Operating revenues – regulated	$397.5	$446.5	$1,417.3	$1,348.2	$1,334.9

Electric Revenues

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

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

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

Q1 Electric Sales Volumes

Gigawatt hours ("GWh")

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

Annual Electric Sales Volumes

GWh

	2015	2014	2013
Residential	4,484	4,370	4,394
Commercial	3,134	3,092	3,148
Industrial	2,457	2,513	2,605
Other	337	312	320
Total	10,412	10,287	10,467

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

Q1 Electric Revenues

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

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

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

Annual Electric Revenues

Millions of Canadian dollars

	2015	2014	2013
Residential	$ 716.0	$ 669.3	$ 654.0
Commercial	410.0	387.3	383.9
Industrial	213.8	213.9	218.0
Other	49.3	48.7	48.4
Total	$1,389.1	$1,319.2	$1,304.3

Electric revenues increased Cdn$8.6 million to Cdn$333.5 million in Q4 2015 compared to Cdn$324.9 million in Q4 2014. For the year ended December 31, 2015, electric revenues increased Cdn$69.9 million to Cdn$1,389.1 million compared to Cdn$1,319.2 million in the same period in 2014. Highlights of the changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Electric revenues – 2013		$1,304.3
Increased electricity pricing effective January 1, 2014		37.9
Decreased commercial and residential sales volumes, in part due to weather		(12.5)
Decreased industrial sales volume		(9.4)
Other		(1.1)

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Electric revenues – 2014	$324.9	$1,319.2
Increased fuel related electricity pricing effective January 1, 2015	13.4	56.0
Decreased commercial and residential sales volumes as a result of decreased load quarter-over-quarter; increased commercial and residential sales volumes year-over-year primarily due to weather and load growth earlier in the year	(4.1)	19.9
Decreased industrial sales volume	(0.6)	(5.2)
Other	(0.1)	(0.8)
Electric revenues – 2015	$333.5	$1,389.1

Regulated Fuel for Generation and Purchased Power

Capacity

To ensure reliability of service, NSPI must maintain a generating capacity greater than firm peak demand. The total NSPI-owned generation capacity is 2,483 MW, which is supplemented by 496 MW contracted with IPPs and the Community Feed-In Tariff ("COMFIT") participants. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on performance indicators. The high availability and capability of low cost thermal generating stations provide lower-cost energy to customers. In 2015, thermal plant availability was 87.9% compared to 84.2% in 2014. NSPI's four-year average for thermal plant availability is 85.1%. While this availability is in line with industry standards, it is particularly significant, as the NSPI coal fleet has a higher capacity factor and better forced outage rate than the standard for its class. In addition, the Company has seen performance improvements in 2015, despite the effects of renewable integration.

Q1 Production Volumes

GWh

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

Annual Production Volumes

GWh

	2015	2014	2013
Coal and petcoke	6,364	6,609	7,098
Natural gas	1,302	1,468	1,317
Oil	265	153	89
Purchased power – other	428	353	491
Total non-renewables	8,359	8,583	8,995
Wind and hydro – renewables	1,275	1,357	1,234
Biomass – renewables	206	258	130
Purchased power – renewables	1,289	849	845
Total renewables	2,770	2,464	2,209
Total production volumes	11,129	11,047	11,204

Q1 Average Fuel Costs

	2016	2015	2014
Dollars per megawatt hour produced	$45	$54	$51

Annual Average Fuel Costs

	2015	2014	2013
Dollars per megawatt hour	$49	$46	$50

Average unit fuel costs decreased in Q1 2016 compared to Q1 2015 primarily due to decreased commodity pricing and decreased load, requiring less generation to be sourced from higher cost alternatives.

Year-over-year, average unit Fuel Costs increased in 2015 compared to the same period in 2014 primarily due to generation costs associated with the COMFIT program and increased load, partially offset by favourable commodity pricing.

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

Historically, coal and petcoke have the lowest per unit fuel cost, after NSPI-owned regulated hydro and wind, which have no fuel cost component. Purchased power, natural gas, oil and biomass have the next lowest fuel cost, depending on the relative pricing of each.

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

A large portion of NSPI's fuel supply comes from international suppliers and is subject to commodity price and foreign exchange risk. NSPI seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. Foreign exchange risk is managed through forward and swap contracts. Fuel contracts may also be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. NSPI has a FAM that enables the Company to seek recovery of Fuel Costs to further manage this risk.

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

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

Regulated fuel for generation and purchased power increased Cdn$5.0 million to Cdn$132.4 million in Q4 2015 compared to Cdn$127.4 million in Q4 2014. For the year ended December 31, 2015, regulated fuel for generation and purchased power increased Cdn$31.1 million to Cdn$542.8 million compared to Cdn$511.7 million in 2014. Highlights of the changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Regulated fuel for generation and purchased power – 2013		$556.9
Decreased commodity prices		(29.0)
Changes in generation mix and plant performance		(11.1)
Decreased sales volumes		(8.8)
Increased hydro and NSPI-owned wind production		(8.1)
Changes in solid fuel mix		14.4
Other		(2.6)
Regulated fuel for generation and purchased power – 2014	$127.4	$511.7
Decreased commodity prices	(6.6)	(38.3)
Changes in generation mix and plant performance	8.5	51.1
Increased (decreased) sales volumes	(1.5)	10.6
Increased hydro and NSPI-owned wind production	5.0	3.0
Other	(0.4)	4.7
Regulated fuel for generation and purchased power – 2015	$132.4	$542.8

Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals

Regulated Fuel Adjustment Mechanism and FAM Regulatory Deferral

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

The FAM is subject to an incentive, with NSPI retaining or absorbing 10% of the over or under-recovered to a maximum of Cdn$5 million. The incentive was suspended for 2012 to 2015, as a result of UARB approved settlement agreements and is in effect for 2016.

In December 2015, the UARB approved NSPI's 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's filings. Approved customer rates reset the base cost of fuel rate for 2016 and seek to recover Cdn$13.7 million of prior years' unrecovered Fuel Costs in 2016. Recovery of these costs began January 1, 2016.

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

The Electricity Plan Act further directed NSPI to apply any non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved and applied to the FAM to be used in the 2017 to 2019 period. The exception to this direction is application of a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would otherwise have been required. This amount totals Cdn$4.6 million. Therefore, as at December 31, 2015, NSPI had deferred Cdn$4.6 million of excess non-fuel revenues to 2016 and Cdn$40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

In Q1 2016, NSPI applied Cdn$3.8 million of non-fuel revenues to the FAM for periods 2017 to 2019. This was as a result of applying the tax benefits associated with the South Canoe and Sable Wind Projects, as directed by the Electricity Plan Act.

In November 2014, the UARB approved a settlement agreement that has resulted in Cdn$56.0 million of the 2014 outstanding FAM balance being collected in 2015. The settlement agreement also reduced the outstanding FAM balance of Cdn$86.1 million by Cdn$38.2 million through an offset from the amount owing to customers as a result of an agreement to allocate non-fuel revenues above NSPI's allowed range of return to the FAM balance, such that the December 31, 2014 FAM regulatory asset was Cdn$47.9 million.

Through a related settlement agreement with stakeholders approved in December 2014, NSPI agreed to apply non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, until the next General Rate Application ("GRA") approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of Cdn$41.3 million to the FAM deferral account by the end of 2015.

As at December 31, 2015, NSPI had exceeded the minimum required contribution of Cdn$41.3 million through the Cdn$38.2 million contributed in 2014, referred to above, and an additional Cdn$44.7 million applied in 2015. Of the Cdn$44.7 million applied in 2015, Cdn$18.3 million relates to changes to the South Canoe and Sable Wind Projects tax treatment.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On July 2, 2014, the FAM audit findings and recommendations relating to fiscal 2012 and 2013 were publicly released, and on January 20, 2015, the UARB disallowed Cdn$6.0 million of 2012 and 2013 fuel-related costs, which included interest of Cdn$0.9 million. The disallowance resulted in a reduction in the amount of FAM deferral in 2014 and resulted in an after-tax impact to 2014 net income of Cdn$3.3 million. The audit for fiscal 2014 and 2015 is currently underway.

The FAM included in the Statements of Income includes the effect of Fuel Costs in both the current and preceding years, specifically, and as detailed in the table below:

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

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

	2016
	millions of Canadian dollars
FAM regulatory liability – Balance as at January 1	$(28.3)
Under (over) recovery of current period Fuel Costs	(10.0)
Rebate to (recovery from) customers of prior years' Fuel Costs	(3.8)
Interest on FAM balance	(0.7)
Application of non-fuel revenues	(3.8)
FAM regulatory liability – Balance as at March 31	$(46.6)

	2015	2014
	millions of Canadian dollars	
FAM regulatory asset – Balance as at January 1	$ 47.9	$ 86.4
Under (over) recovery of current year Fuel Costs	24.1	(1.3)
Rebate to (recovery from) customers of prior years' Fuel Costs	(56.0)	—
FAM audit disallowance, including interest adjustment	—	(6.0)
Application of non-fuel revenues	(44.7)	(38.2)
Interest on FAM balance	0.4	7.0
FAM regulatory asset (liability) – Balance as at December 31	$(28.3)	$ 47.9

Of the Cdn$44.7 million non-fuel revenues applied in 2015, Cdn$40.1 million is to be applied to the FAM during the 2017 to 2019 period and Cdn$4.6 million will be applied in 2016.

Regulated Fixed Cost Deferrals and Fixed Cost Recovery Deferral Regulatory Assets

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

<u>DSM Deferral</u>

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities (the "DSM Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The DSM Program Costs were set for 2015 at Cdn$35.0 million and have been deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of Cdn$102.0 million for the three- year period of 2016 through 2018. The Electricity Plan Act has placed a cap of Cdn$34.0 million on the 2019 DSM spending. The 2016 DSM cost of Cdn$24.7 million will not be deferred. A decision of the timing of the cost recovery for 2017 through 2019 will be made at a future date.

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

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

	2015
	millions of Canadian dollars
DSM regulatory asset – Balance as at January 1	$ —
Current period DSM Program Costs	35.0
Interest on DSM balance	1.4
DSM regulatory asset – Balance as at December 31	$36.4

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a deferral of recovery of certain fixed costs for fiscal 2013 and 2014 as part of a rate stabilization plan. As previously noted above under the Regulated Fuel Adjustment Mechanism, the resulting regulatory liability at the end of 2014 of Cdn$38.2 million was applied against the FAM regulatory asset balance in 2014 and is included in the application of non-fuel revenues line in the table above.

Electric Margin

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

Electric margin (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP—Electric Margin Reconciliation") is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to NSPI's Non-Fuel Electric Revenues, with residential and commercial customers contributing more than industrial customers under current rates. Accordingly, changes in residential and commercial load, largely due to the effects of weather, from general economic conditions and from DSM have the largest effect on Non-Fuel Electric Revenues and electric margin. Changes in industrial load, which are generally due to economic conditions, have less of an effect on Non-Fuel Electric Revenues than would a similar volume change in residential and commercial load.

The addition of new generation sources to meet legislated greenhouse gas emission reductions and renewable generation requirements is among the drivers increasing NSPI's fixed costs. Electric margin, which represents revenues available to cover these costs, has increased in a corresponding manner.

Operating revenues are summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014[(1)]	2013[(1)]
	millions of Canadian dollars				
Fuel Electric Revenues – current year	$ 152.0	$ 165.7	$ 518.5	$ 512.5	$ 488.7
Fuel Electric Revenues – recovery of preceding years	3.8	18.2	56.0	—	29.8
Non-Fuel Electric Revenues	235.9	256.1	814.6	806.7	785.8
Other revenues	5.8	6.5	28.2	29.0	30.6
Operating revenues	$ 397.5	$ 446.5	$1,417.3	$1,348.2	$1334.9

Electric margin is summarized in the following table:

Fuel Electric Revenues – current year	$ 152.0	$ 165.7	$ 518.5	$ 512.5	$ 488.7
Fuel Electric Revenues – recovery of preceding years	3.8	18.2	56.0	—	29.8
Total Fuel Electric Revenues	155.8	183.9	574.5	512.5	518.5
Regulated fuel for generation and purchased power	(141.5)	(189.4)	(542.8)	(511.7)	(556.9)
Regulated fuel adjustment mechanism	(13.8)	5.4	(31.9)	(6.4)	37.8
Fuel-related foreign exchange gain (loss)[(2)]	0.2	0.1	0.2	0.5	0.6
Net fuel revenue (expense)	0.7	—	—	(5.1)	—
Non-Fuel Electric Revenues	235.9	256.1	814.6	806.7	785.8
Electric margin	$ 236.6	$ 256.1	$ 814.6	$ 801.6	$ 785.8

(1) NSPI removed "Fixed cost deferrals" from its calculation of electric margin in Q2 2014 as management believed it better reflected its business operations. Prior periods have been retroactively restated.
(2) As reported in "Other income (expenses) net," on the Consolidated Statement of Income.

NSPI's electric margin decreased Cdn$19.5 million to Cdn$236.6 million in Q1 2016 compared to Cdn$256.1 million in Q1 2015 due to decreased Non-Fuel Electric Revenues primarily due to decreased residential and commercial sales reflecting decreased load, primarily due to weather. NSPI's electric margin for the year ended December 31, 2015 increased Cdn$13.0 million to Cdn$814.6 million compared to Cdn$801.6 million in 2014 primarily due to increased residential load, largely due to weather and a FAM audit disallowance in 2014.

Q1 Average Electric Margin/MWh

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

Annual Average Electric Margin/MWh

	2015	2014	2013
Dollars per MWh	$78	$78	$75

NSPI's electric margin per MWh is consistent quarter-over-quarter and year-over-year.

Regulatory Amortization

Regulatory amortization is included in "Depreciation and amortization" on the Consolidated Statements of Income. Highlights of the changes in regulatory amortization are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Regulatory amortization – 2013		$ 37.4
Decreased pre-2003 income tax regulatory asset amortization(1)		(14.0)
2012 Large Industrial Customers FCR amortization, which commenced in 2013, following the 2013 General Rate Application settlement agreement		2.4
Other regulatory amortization		(0.9)
Regulatory amortization – 2014	$ 8.9	$ 24.9
Decreased 2012 Large Industrial Customers Fixed Cost Recovery amortization, which commenced in 2013, following the 2013 General Rate Application settlement agreement	(2.7)	(2.7)
Other regulatory amortization	(1.6)	(1.4)
Regulatory amortization – 2015	$ 4.6	$ 20.8

(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.

Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

Income Taxes

NSPI is subject to corporate income tax at the statutory rate of 31.0% (combined federal and provincial income tax rate) and Part VI.1 tax relating to preferred stock dividends at the statutory rate of 40.0%. NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction of 43.4% of preferred stock dividends.

Non-U.S. GAAP Measure

Electric Margin Reconciliation

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

	Three months ended March 31		Year ended December 31		
	2016	**2015**	**2015**	**2014**[1]	**2013**[1]
	millions of Canadian dollars				
Income from operations	$ 92.9	$123.6	$289.8	$274.0	$295.0
Less:					
Fuel Electric Revenues – current and preceding years	155.8	183.9	574.5	512.5	518.5
FAM audit disallowance	—	—	—	5.1	—
Other revenues	5.8	6.5	28.2	29.0	30.6
Add back:					
Regulated fuel for generation and purchased power	141.5	189.4	542.8	511.7	556.9
Operating, maintenance and general	87.4	79.6	298.1	273.6	272.3
Property, state and municipal taxes[1]	9.7	9.6	38.5	38.3	37.7
Depreciation and amortization[2]	48.4	51.5	206.5	204.0	213.8
Regulated fuel adjustment mechanism and fixed	17.6	(7.2)	41.6	46.6	(40.8)
Other fuel related costs	0.7	—	—	—	—
Electric margin	$236.6	$256.1	$814.6	$801.6	$785.8

Emera Maine

Overview

Emera Maine is a transmission and distribution electric utility with assets of approximately Cdn$1.1 billion serving approximately 158,000 customers in the State of Maine in the United States. Effective January 1, 2014, Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS") merged, becoming Emera Maine.

Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine's transmission and distribution networks. Emera Maine owns and operates approximately 1,700 kilometres of transmission facilities and 15,000 kilometres of distribution facilities. Emera Maine's workforce is approximately 400 people.

Distribution Operations

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. Prior to July 1, 2014, the allowed ROE was 10.2%, on a common equity component of 50%. On July 1, 2014, Emera Maine's distribution rates increased by 9%. Effective July 1, 2014, the allowed ROE became 9.55%, on a common equity component of 49%.

Transmission Operations

There are two transmission districts in Emera Maine, corresponding to the service territories of the two pre-merger entities.

Bangor Hydro District

Local transmission rates for Bangor Hydro District (the franchise electric service territory associated with the former Bangor Hydro Electric Company in portions of the Maine counties of Penobscot, Hancock, Washington, Waldo, Piscataquis, and Aroostook) are regulated by the FERC and set annually on June 1, based on a formula utilizing prior year actual transmission investments, adjusted for current year forecasted transmission investments. For local transmission operations, the rate for the Bangor Hydro District is set on a 10.57% ROE. The allowed ROE up to October 15, 2014, for these local transmission investments, was 11.14%. Effective October 16, 2014, the allowed ROE changed to 10.57%, pending two outstanding complaints filed with the FERC to challenge the ISO-New England Open Access Transmission Tariff-allowed base ROE of 11.14%. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015, transmission rates for the Bangor Hydro District increased by approximately 21% in connection with its annual transmission formula rate filing (2014 – increased by 13%). The increase is associated primarily with the under-recovery of prior year regional transmission revenues collected in local rates, as well as the recovery of increased transmission plant in service.

The Bangor Hydro District's bulk transmission assets are managed by ISO-NE as part of a region-wide pool of assets. ISO-NE manages the region's bulk power generation and transmission systems and administers the open access transmission tariff. Currently, the Bangor Hydro District along with all other participating transmission providers, recovers the full cost of service for its transmission assets from the customers of participating transmission providers in New England, based on a regional FERC approved formula that is updated June 1 each year. This formula is based on prior year regionally funded transmission investments, adjusted for current year forecasted investments. Until October 15, 2014, Bangor Hydro District's allowed ROE for these transmission investments ranged from 11.64% to 12.64%. Effective October 16, 2014, the transmission investments allowed ROE changed to a range from 11.07% to 11.74%, pending the two aforementioned complaints filed with FERC. The common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent.

On June 1, 2015, Bangor Hydro District's regionally recoverable transmission investments and expenses decreased by 6% (2014 – increased by 7%).

As at December 31, 2015, the Company had accrued Cdn$5.0 million associated with the FERC ROE complaints (2014 – Cdn$7.3 million). Refunds for the first FERC ROE complaint are being made to customers over a one-year period which began with the June 1, 2015 rate change.

MPS District

Local transmission rates for MPS District's (the franchise electric service territory associated with the former Maine Public Service Company in the Maine counties of Aroostook and a portion of Penobscot) are regulated by the FERC and are set annually on June 1 for wholesale and July 1 for retail customers, based on a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted investments. The current allowed ROE for transmission operations is 10.2%. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015 the transmission rates for the MPS District decreased by approximately 24% for wholesale customers (2014 – increased by 2%) and on July 1, 2015 decreased by 22% for retail customers (2014 – increased by 11%) in connection with its annual transmission formula rate filing. These decreases were primarily due to an increase in wholesale transmission revenue that allows for a decrease in local customer transmission rates.

The MPS District electric service territory is not connected to the New England bulk power system and it is not a member of ISO-NE. MPS District is not a party to the previously discussed ROE complaints at the FERC.

Stranded Cost Recoveries

Stranded cost recoveries in Maine are set by the MPUC. Electric utilities are permitted to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike transmission and distribution operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, determined under a traditional cost-of-service approach and are fully recoverable.

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

Each year on July 1, stranded cost rates are adjusted to reflect recovery of cost deferrals for the prior stranded costs rate year under the full recovery mechanism, as well as factor in any new stranded cost information.

Bangor Hydro District

Bangor Hydro District's net stranded regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract, and deferrals associated with reconciling stranded costs. These net regulatory assets total approximately Cdn$19.7 million as at December 31, 2015 (2014 – Cdn$25.1 million) or 1.8% of Emera Maine's net asset base (2014 – 2.3%).

On July 1, 2014, the Bangor Hydro District stranded cost rates decreased by 10%. Earlier, on March 1, 2014, stranded costs rates had increased by 20%. The allowed ROE used in setting the new rates on July 1, 2014, and March 1, 2014, was 5.9%, with a common equity component of 48%. This July 1, 2014 rate decrease remained in effect for all of 2015, and there was no rate change on July 1, 2015.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To stabilize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

MPS District

Effective January 1, 2015, the stranded cost rates for the MPS District decreased by approximately 150%. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The allowed ROE used in setting the new rates on January 1, 2015 was 6.75%, with a common equity component of 48%. The reduced stranded cost revenues are offset by reductions in expense and do not affect income. This January 1, 2015, rate decrease remained in effect for all of 2015 and there was no rate change on July 1, 2015.

Review of 2016 and 2015

Emera Maine Net Income

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars (except per share amounts)				
Operating revenues – regulated	$57.7	$55.8	$221.6	$219.0	$211.2
Operating revenues – non-regulated	0.2	—	0.6	0.5	0.5
Total operating revenues	57.9	55.8	222.2	219.5	211.7
Regulated fuel for generation and purchased power	7.8	7.7	28.9	29.7	30.8
Transmission pool expense[(1)]	6.3	6.1	25.4	23.9	22.9
Operating, maintenance and general	15.9	13.2	49.1	47.0	44.2
Provincial, state and municipal taxes	3.6	3.5	12.8	11.5	10.2
Depreciation and amortization	10.7	8.8	36.5	43.3	35.9
Total operating expenses	44.3	39.3	152.7	155.4	144.0
Income from operations	13.6	16.5	69.5	64.1	67.7
Other income (expenses), net	0.2	1.1	0.8	4.2	3.3
Interest expense, net	3.6	3.4	13.7	12.2	12.2
Income before provision for income taxes	10.2	14.2	56.6	56.1	58.8
Income tax expense (recovery)	3.4	4.9	21.0	17.7	21.6
Contribution to consolidated net income – USD	$ 6.8	$ 9.3	$ 35.6	$ 38.4	$ 37.2
Contribution to consolidated net income – CAD	$ 9.3	$11.5	$ 45.1	$ 42.4	$ 38.4
Contribution to consolidated earnings per common share – CAD	$0.06	$0.08	$ 0.31	$ 0.30	$ 0.29
Net income weighted average foreign exchange rate – CAD/USD	$1.37	$1.24	$ 1.27	$ 1.10	$ 1.03
EBITDA – USD[(2)]	$24.5	$26.4	$106.8	$111.6	$106.9
EBITDA – CAD[(2)]	$33.5	$32.8	$136.0	$123.4	$110.3

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

(2) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures".

Emera Maine's USD contribution to consolidated net income in Q1 2016 decreased by US$2.5 million to US$6.8 million compared to $9.3 million in Q1 2015. Highlights of the USD net income changes are summarized in the following table:

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

Emera Maine's USD contribution to consolidated net income decreased by U.S.$6.4 million to U.S.$3.9 million in Q4 2015 compared to U.S.$10.3 million in Q4 2014. For the year ended December 31, 2015, Emera Maine's USD contribution to consolidated net income decreased by U.S.$2.8 million to U.S.$35.6 million compared to U.S.$38.4 million in 2014. Highlights of the USD net income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of U.S. dollars	
Contribution to consolidated net income – 2013		$37.2
Increased operating revenues primarily due to rate changes		7.8
Decreased regulated fuel for purchased power primarily due to changes in purchased power contracts		1.1
Increased OM&G expenses primarily due to decreased capitalized construction overheads and increased storm expenses		(2.8)
Increased depreciation and amortization primarily due to increased plant in service		(7.4)
Decreased income tax expense primarily due to decreased income before provision for income taxes, a change in estimate of prior year expected benefit of tax deductions and changes in regulatory amortization		3.9
Other		(1.4)
Contribution to consolidated net income – 2014	$10.3	$38.4
(Decreased) increased operating revenues – see "—Operating Revenues – Regulated"	(3.3)	2.6
Increased OM&G primarily due to decreased capitalized construction overheads, partially offset by changes in pension and retiree medical expenses	(3.9)	(2.1)
Decreased depreciation and amortization due to lower depreciation rates as a result of a 2014 depreciation study and lower regulatory amortization; no change quarter-over-quarter as lower depreciation rates are offset by increased regulatory amortization	—	6.8
Decreased other income primarily due to AFUDC adjustments recognized as a result of a FERC audit	(2.8)	(3.4)
Decreased income tax expense quarter-over-quarter primarily due to lower income before provision for income taxes, partially offset by AFUDC adjustments recorded as a result of a FERC audit; year-over-year increase primarily due to decrease in regulatory amortization and AFUDC adjustments recorded as a result of a FERC audit	1.2	(3.3)
Other	2.4	(3.4)
Contribution to consolidated net income – 2015	$ 3.9	$35.6

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

Emera Maine's CAD contribution to consolidated net income decreased by $6.5 million to $5.2 million in Q4 2015 from $11.7 million in Q4 2014. For the year ended December 31, 2015, Emera Maine's CAD contribution to consolidated net income increased by $2.7 million to $45.1 million from $42.4 million in 2014. The impact of a stronger USD, increased CAD earnings quarter-over-quarter by $0.7 million for the three months ended December 31, 2015 and year-over-year $6.1 million for the year ended December 31, 2015.

Operating Revenues—Regulated

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

Q1 Operating Revenue—Regulated

Millions of U.S. dollars

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

Annual Operating Revenue—Regulated

Millions of U.S. dollars

	2015	**2014**	**2013**
Electric revenues	$160.0	$156.8	$146.9
Transmission pool revenues	49.1	49.0	50.7
Resale of purchased power	12.5	13.2	13.6
Operating revenues – regulated	$221.6	$219.0	$211.2

Electric Revenues

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

Q1 Electric Sales Volumes

GWh

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

Annual Electric Sales Volumes

GWh

	2015	**2014**	**2013**
Residential	802	805	801
Commercial	781	788	798
Industrial	423	426	424
Other	14	15	15
Total	2,020	2,034	2,038

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

Q1 Electric Revenues

	2016	2015	2014
	millions of U.S. dollars		
Residential	$20.7	$21.6	$20.7
Commercial	14.8	14.3	14.9
Industrial	3.2	3.3	4.1
Other(1)	3.0	0.8	2.7
Total	$41.7	$40.0	$42.4

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

Annual Electric Revenues

Millions of U.S. dollars

	2015	2014	2013
Residential	$ 76.4	$ 75.8	$ 71.7
Commercial	57.9	57.2	54.7
Industrial	14.1	14.2	13.1
Other(1)	11.6	9.6	7.4
Total	$160.0	$156.8	$146.9

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

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

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

For the year ended December 31, 2015, electric revenues increased US$3.2 million to US$160.0 million in 2015 compared to US$156.8 million in 2014. Highlights of the changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of U.S. dollars	
Electric revenues – 2013		$146.9
Decreased sales volumes primarily due to weather		(0.2)
Increased primarily due to rate changes		9.5
Decreased due to changes in amounts recognized related to the FERC ROE complaints		(2.6)
Change in estimate for the transmission revenue		3.2
Electric revenues – 2014	$41.2	$156.8
Decreased sales volumes primarily due to weather	(1.2)	(1.1)
Increased primarily due to rate changes	0.5	3.8
Increased due to FERC transmission rate refund	3.9	6.0
Decreased due to transmission revenue adjustments	(6.4)	(5.5)
Electric revenues – 2015	$38.0	$160.0

Q1 Average Electric Revenue/MWh

	2016	2015	2014
		U.S. dollars	
Dollars per MWh	$83	$73	$78

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

Annual Electric Revenue

MWh

	2015	2014	2013
Dollars per MWh	$79	$77	$72

The change in average electric revenue per MWh in for the year ended December 31, 2015 compared to the same period in 2014 reflects transmission revenue adjustments and changes in the amounts recorded related to the transmission rate refund associated with the FERC ROE complaints.

Transmission Pool Revenues and Expenses

Transmission pool revenues are recorded in "Operating revenues—regulated" and transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

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

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
			millions of U.S. dollars		
Transmission pool revenues	$11.6	$12.2	$49.1	$49.0	$50.7
Transmission pool expenses	6.3	6.1	25.4	23.9	22.9
Net transmission pool revenues	$ 5.3	$ 6.1	$23.7	$25.1	$27.8

Emera Maine's net transmission pool revenues decreased US$0.8 million to US$5.3 million in Q1 2016 compared to US$6.1 million in Q1 2015 primarily due to changes in the level of investment in regionally funded transmission assets and the effect of weather.

For the year ended December 31, 2015, net transmission pool revenues decreased US$1.4 million to US$23.7 million compared to US$25.1 million in 2014 primarily due to changes in the level of investment in regionally funded transmission assets and the impacts of weather in the New England region.

Resale of Purchased Power and Regulated Fuel for Generation and Purchased Power

Emera Maine has several above-market power purchase contracts with generators in its Bangor Hydro District service territory. The power purchased under these arrangements is resold at market rates significantly below the contract rates. The difference between the cost of the power purchased under these arrangements and the revenue collected is recovered through stranded cost rates under a full reconciliation rate mechanism.

Resale of purchased power increased US$0.2 million in Q4 2015 to US$3.6 million compared to US$3.4 million in Q4 2014, and for the year ended December 31, 2015 decreased US$0.7 million to US$12.5 million in 2015 compared to US$13.2 million in 2014 primarily due to changes in market rates for electricity in New England in 2015.

Income Taxes

Emera Maine is subject to corporate income tax at the statutory rate of 40.8% (combined U.S. federal and state income tax rate).

Emera Caribbean

Overview

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

Consolidated Investments

- 100.0% (December 31, 2015 – 95.5%) investment in Emera (Caribbean) Incorporated and its wholly owned subsidiary Barbados Light & Power Company Ltd., a vertically integrated utility and the provider of electricity on the island of Barbados, serving approximately 126,000 customers and regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. BLPC owns 239 MW of oil-fired generation, 116 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC has a workforce of 330 people. BLPC is regulated under a cost-of-service model with rates set to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. BLPC's approved allowed regulated return on rate base for 2016 is 10.0%. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. Emera completed the purchase of the remaining 4.5% of common shares from minority shareholders of ECI in Q1 2016.
- 50.0% direct and 30.4% indirect interest through a 60.7% interest in ICD Utilities Limited in Grand Bahama Power Company Ltd. which is a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves approximately 19,000 customers. GBPC owns 98 MW of oil-fired generation, 138 kilometres of transmission facilities and 850 kilometres of distribution facilities and has a workforce of 205 people. GBPC is regulated by GBPA, which has granted GBPC a licensed, regulated and exclusive franchise to generate, transmit and distribute electricity on the island until 2054. A fuel pass-through mechanism provides the opportunity to recover

all fuel costs in a timely manner. Effective February 1, 2016, the GBPA approved GBPC's General Rate Application of 8.8% applicable for the 2016 through 2018 period. Residential customers will see decreases up to 4.5%, while commercial customers will see an increase of 1.5%. Commercial customers consume approximately 70% of GBPC's production. This rate decision will allow for customers to install renewable energy systems and sell their excess energy to GBPC. This is based on a tariff rider scheduled to be in place by Q3 2016.

- 51.9% (December 31, 2015 – 49.6% indirect controlling interest), through ECI, in Dominica Electricity Services Ltd., an integrated utility on the island of Dominica. Domlec serves approximately 36,000 customers and is regulated by the Independent Regulatory Commission, Dominica. Domlec owns 20 MW of oil-fired generation, 7 MW of hydro production, 452 kilometres of transmission facilities and 640 kilometres of distribution facilities. Domlec has a workforce of 238 people. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base for 2016 is 15.0%. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.
- EUS Bahamas, providing utility construction and plant operation services in The Bahamas.

Equity Investment

- 19.1% (December 31, 2015 – 18.2% indirect interest), through ECI, in St. Lucia Electricity Services Limited, a vertically integrated regulated electric utility on the island of St. Lucia, which is regulated by the Government of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2016 and 2015

Emera Caribbean Net Income

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars (except per share amounts)				
Operating revenues – regulated	$71.0	$83.1	$346.0	$432.1	$427.4
Operating revenues – non-regulated	—	1.9	6.0	8.0	8.7
Total operating revenues	71.0	85.0	352.0	440.1	436.1
Regulated fuel for generation and purchased power	26.7	39.1	158.1	247.6	248.6
Non-regulated direct costs	—	1.8	5.9	7.1	7.6
Operating, maintenance and general	21.6	22.8	101.5	107.3	103.7
Property taxes(1)	0.6	0.4	1.8	1.6	1.5
Depreciation and amortization	9.4	8.6	34.5	33.3	30.9
Total operating expenses	58.3	72.7	301.8	396.9	392.3
Income from operations	12.7	12.3	50.2	43.2	43.8
Income from equity investment	0.4	0.5	2.3	2.1	1.7
Other income (expenses), net	0.3	1.5	4.8	5.7	11.8
Interest expense, net	2.8	2.7	10.8	11.5	11.7
Income before provision for income taxes	10.6	11.6	46.5	39.5	45.6
Income tax expense (recovery)	1.0	1.0	2.4	2.7	3.2
Net income	9.6	10.6	44.1	36.8	42.4
Non-controlling interest in subsidiaries	1.2	2.2	10.2	8.3	8.9
Preferred stock dividends(2)	1.3	1.3	2.5	2.5	1.2
Contribution to consolidated net income – USD	$ 7.1	$ 7.1	$ 31.4	$ 26.0	$ 32.3

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014(1)	2013(1)
	millions of U.S. dollars (except per share amounts)				
Contribution to consolidated net income – CAD	$ 9.8	$ 8.8	$ 40.5	$ 28.7	$ 33.4
Contribution to consolidated earnings per common share – CAD	$0.07	$0.06	$ 0.28	$ 0.20	$ 0.25
Net income weighted average foreign exchange rate – CAD/USD	$1.38	$1.24	$ 1.29	$ 1.10	$ 1.03
EBITDA – USD(3)	$22.8	$22.9	$ 91.8	$ 84.3	$ 88.2
EBITDA – CAD(3)	$31.5	$28.3	$117.9	$ 93.0	$ 91.1

(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.
(3) A non-U.S. GAAP measure described in “Management’s Discussion and Analysis—Non-U.S. GAAP Financial Measures”.

Emera Caribbean’s USD contribution to consolidated net income did not change in Q1 2016 compared to Q1 2015.

For the year ended December 31, 2015, Emera Caribbean’s USD contribution to consolidated net income increased by U.S.$5.4 million to U.S.$31.4 million compared to U.S.$26.0 million in 2014. Highlights of the net income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of U.S. dollars	
Contribution to consolidated net income – 2013		$32.3
Increased OM&G expenses due to restructuring costs at ECI, partially offset by operational cost savings at GBPC		(0.4)
Decreased other income (expenses), net primarily due to reduced investment income relating to an adjustment to ECI’s self-insurance fund		(3.4)
Increased preferred dividends due to timing of preferred share issuance		(1.3)
Effect of the non-taxable gain on acquisition of Domlec, partially offset by the acquisition of controlling interest in Domlec on April 10, 2013		(2.0)
Other		0.8
Contribution to consolidated net income – 2014	$ 5.3	$26.0
Increased Electric Margin – see “Electric Margin”	1.8	3.7
Decreased OM&G primarily due to lower pension expense, savings and timing of maintenance costs, and restructuring payroll savings at BLPC, lower outage costs at GBPC, and the reversal of Domlec regulatory costs; year-over-year restructuring costs at BLPC offset the decreased OM&G	4.9	5.8
Increased non-controlling interest due to increased earnings from ECI, GBPC and Domlec	(1.0)	(1.9)
Other	(1.0)	(2.2)
Contribution to consolidated net income – 2015	$10.0	$31.4

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

For the year ended December 31, 2015, Emera Caribbean’s CAD contribution to consolidated net income increased by Cdn$11.8 million to Cdn$40.5 million in 2015 compared to Cdn$28.7 million in 2014. The impact of a stronger USD year-over-year increased CAD earnings by Cdn$6.0 million in 2015 compared to 2014.

Operating Revenues—Regulated

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

Q1 Operating Revenues—Regulated

Millions of U.S. dollars

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

Annual Operating Revenues—Regulated

Millions of U.S. dollars

	2015	**2014**	**2013[(1)]**
Electric revenues – base rates	$186.7	$182.7	$177.0
Fuel charge	155.4	245.2	247.0
Total electric revenues	342.1	427.9	424.0
Other revenues	3.9	4.2	3.4
Operating revenues – regulated	$346.0	$432.1	$427.4

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

Electric Revenues

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

Q1 Electric Sales Volumes

GWh

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

Annual Electric Sales Volumes

GWh

	2015	2014	2013(1)
Residential	453	440	428
Commercial	764	751	744
Industrial	104	102	93
Other	24	26	26
Total	1,345	1,319	1,291

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

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

Q1 Electric Revenues

	2016	2015	2014
	millions of U.S. dollars		
Residential	$22.5	$25.9	$31.2
Commercial	39.3	46.1	58.5
Industrial	6.8	8.6	8.4
Other	1.5	1.6	1.7
Total	$70.1	$82.2	$99.8

Annual Electric Revenues

Millions of U.S. dollars

	2015	2014	2013(1)
Residential	$110.9	$142.9	$133.2
Commercial	194.8	250.7	251.5
Industrial	30.1	26.9	31.5
Other	6.3	7.4	7.8
Total	$342.1	$427.9	$424.0

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

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

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

Electric revenues decreased US$21.2 million to US$83.4 million in Q4 2015 compared to US$104.6 million in Q4 2014. For the year ended December 31, 2015, electric revenues decreased US$85.8 million to US$342.1 million compared to US$427.9 million in 2014. Highlights of the changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of U.S. dollars	
Electric revenues – 2013		$424.0
Increased due to acquisition of a controlling interest in Domlec		8.2
Decreased fuel charge primarily due to lower fuel prices		(4.8)
Increased due to higher sales volumes in GBPC		0.5
Electric revenues – 2014	$104.6	$427.9
Decreased fuel charge primarily due to lower fuel prices	(23.1)	(89.8)
Increased due to higher sales volumes at BLPC and GBPC primarily due to weather	1.9	4.0
Electric revenues – 2015	$ 83.4	$342.1

Q1 Average Electric Revenue/MWh

	2016	2015	2014
		U.S. dollars	
Dollars per MWh	$221	$259	$320

The change in average electric revenues per MWh in Q1 2016 compared to Q1 2015 was the result of the decreased fuel charge primarily due to lower fuel prices.

Annual Average Electric Revenue

MWh

	2015	2014	2013[(1)]
Dollars per MWh	$254	$324	$328

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

The change in average electric revenues for the year ended December 31, 2015 compared to the same period in 2014, is a result of the decreased fuel charge primarily due to lower fuel prices.

Electric Margin

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

Electric margin (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP—Electric Margin Reconciliation") is summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars				
Operating revenues – regulated	$71.0	$83.1	$346.0	$432.1	$427.4
Less: Other revenues	(0.9)	(0.9)	(3.9)	(4.2)	(3.4)
Total electric revenues	70.1	82.2	342.1	427.9	424.0
Total electric revenues are broken down as follows:					
Electric revenues – base rate	44.0	43.6	186.7	182.7	177.0
Fuel charge	26.1	38.6	155.4	245.2	247.0
Total electric revenues	70.1	82.2	342.1	427.9	424.0
Regulated fuel for generation and purchased power	26.7	39.1	158.1	247.9	248.6
Regulatory amortization[2]	0.6	0.7	2.9	2.9	2.9
Electric margin	$42.8	$42.4	$181.1	$177.4	$172.5

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.
(2) Included in "Depreciation and amortization" on the Consolidated Statements of Income.

Emera Caribbean's electric margin increased US$1.8 million to US$45.7 million in Q4 2015 compared to US$43.9 million in Q4 2014. For the year ended December 31, 2015, electric margin increased US$3.7 million to US$181.1 million compared to US$177.4 million in 2014 primarily due to increased sales volume at BLPC and GBPC primarily due to weather.

Q1 Average Electric Margin

MWh

	2016	2015	2014
		U.S. dollars	
Dollars per MWh	$135	$134	$133

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

Annual Average Electric Margin

MWh

	2015	2014	2013[1]
Dollars per MWh	$135	$134	$134

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013

Regulated Fuel for Generation and Purchased Power

Q1 Production Volumes

GWh

	2016	2015	2014
		U.S. dollars	
Oil	337	335	330
Hydro	9	7	8
Total	346	342	338

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

Annual Production Volumes

GWh

	2015	2014	2013
Oil	1,441	1,397	1,371
Hydro	25	31	30
Total	1,466	1,428	1,401

Q1 Average Fuel Costs/MWh

	2016	2015	2014
		U.S. dollars	
Dollars per MWh	$77	$114	$170

The change in average fuel costs in Q1 2016 compared to Q1 2015 was the result of lower fuel prices.

Annual Average Fuel Costs

MWh

	2015	2014	2013[1]
Dollars per MWh	$108	$173	177

(1) ECI acquired a 51.9% controlling interest in Domlec on April 10, 2013.

The change in average fuel costs for the year ended December 31, 2015 compared to the same period in 2014 is a result of lower fuel prices.

For the year ended December 31, 2015, regulated fuel for generation and purchased power decreased US$89.5 million to US$158.1 million compared to US$247.6 million in 2014 primarily due to lower fuel prices.

Regulatory Recovery Mechanisms

BLPC

All BLPC fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover all fuel costs in a timely manner. The Fair Trading Commission, Barbados has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

GBPC

All GBPC fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover all fuel costs in a timely manner. The GBPA has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

As a component of its regulatory agreement with the GBPA, GBPC has an earnings share mechanism to allow for earnings on rate base to be deferred to a regulatory asset or liability at the rate of 50% of amounts below a nine-percent return on rate base and 50% of amounts above 11% return on rate base respectively.

Domlec

Substantially all of Domlec fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover fuel costs in a timely manner.

Income Taxes

Emera Caribbean is subject to corporate income tax at the following statutory rates:

- ECI is subject to corporate income tax at the statutory rate of 25.0%;
- BLPC is subject to corporate income tax at the statutory rate of 15.0%;
- GBPC is not subject to corporate income tax;
- Domlec is subject to corporate income tax at the statutory rate of 28.0%; and
- Lucelec is subject to corporate income tax at the statutory rate of 30.0%.

Non-U.S. GAAP Measure

Electric Margin Reconciliation

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

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

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of U.S. dollars				
Income from operations	$12.7	$12.3	$ 50.2	$ 43.2	$ 43.8
Less:					
Operating revenues – non-regulated	—	1.9	6.0	8.0	78.7
Other revenue	0.9	0.9	3.9	4.2	3.4
Add back:					
Non-regulated direct costs	—	1.8	5.9	7.1	7.6
Operating, maintenance and general	21.6	22.8	101.5	107.3	103.7
Property taxes	0.6	0.4	1.8	1.6	1.5
Depreciation and amortization(1)	8.8	7.9	31.6	304.	28.0
Electric margin	$42.8	$42.4	$181.1	$177.4	$172.5

(1) Depreciation and amortization excludes $0.6 million of regulatory amortization in Q1 2016 (2015 – $0.7 million) and $2.9 million for the year ended December 31, 2015 (2014 – $2.9 million)

Pipelines

Overview

Pipelines comprises Emera's wholly owned Brunswick Pipeline and the Company's 12.9% interest in the M&NP.

- Brunswick Pipeline is a 145-kilometre pipeline delivering re-gasified natural gas from the Canaport™ liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States for Repsol Energy Canada Ltd. ("RECL") under a 25-year firm service agreement which expires in 2034. The NEB, which regulates the Brunswick Pipeline, has classified it as a Group II pipeline. The agreement is accounted for as a direct financing lease.
- M&NP is a 1,400-kilometre transmission pipeline built to transport natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States. The investment in M&NP is accounted for on the equity basis.

Mark-to-Market Adjustments

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

Review of 2016 and 2015

Pipelines' Adjusted Net Income (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures")

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Operating revenues – regulated	$12.9	$13.1	$52.1	$48.8	$49.9
Operating, maintenance and general	0.1	0.2	0.4	0.4	0.1
Accretion(1)	0.1	0.1	0.4	0.3	0.2
Income from equity investment	5.9	5.9	23.0	18.4	14.7
Other income (expenses), net	(0.2)	0.7	0.6	0.6	0.1
Interest expense, net(2)	5.7	6.2	23.3	26.0	27.6
Adjusted income before provision for income taxes	12.7	13.2	51.6	41.1	36.8
Income tax expense (recovery)(3)	3.0	3.3	12.0	8.4	6.5
Adjusted contribution to consolidated net income	$ 9.7	$ 9.9	$39.6	$32.7	$30.3
After-tax derivative mark-to-market gain (loss)	(0.3)		(2.1)		—
Contribution to consolidated net income	$ 9.4	$ 9.9	$37.5	$32.7	$30.3
Adjusted contribution to consolidated earnings per common share	$0.07	$0.07	$0.27	$0.23	$0.23
Contribution to consolidated earnings per common share	$0.06	$0.07	$0.26	$0.23	$0.23
Adjusted EBITDA	$18.5	$19.5	$75.3	$67.4	$64.6

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

(2) Interest expense, net excludes a pre-tax mark-to-market loss of $0.3 million in Q1 2016 compared to nil for the same period in 2015 and $2.9 million loss for the year ended December 31, 2015 compared to nil for the same period in 2014.

(3) Income tax expense (recovery) excludes $0.8 million recovery relating to mark-to-market losses for the year ended December 31, 2015 compared to nil for the same periods in 2014.

Pipelines' contribution to consolidated net income in Q1 2016 is consistent with Q1 2015.

Pipelines' contribution to consolidated net income increased by Cdn$1.8 million to Cdn$10.3 million in Q4 2015 compared to Cdn$8.5 million in Q4 2014 and increased Cdn$4.8 million to Cdn$37.5 million for the year ended December 31, 2015 compared to Cdn$32.7 million in 2014. Highlights of the income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Contribution to consolidated net income – 2013		$30.3
Increased income from equity investments primarily due to higher equity earnings from M&NP		3.7
Other		(1.3)
Contribution to consolidated net income – 2014	$ 8.5	$32.7
Increased regulated operating revenues due to a strengthening USD and increased tolls	0.6	3.3
Increased income from equity investments primarily due to increased interruptible transmission revenue from M&NP and the strengthening USD	1.2	4.6
Decreased interest expense, net primarily due to a lower interest rate on EBPC refinancing in Q1 2015	0.8	2.7
Increased income tax expense primarily due to increased income before provision for income taxes	(0.8)	(3.6)
After-tax mark-to-market gain (loss) on an interest rate swap entered into in Q2 2015	0.2	(2.1)
Other	(0.2)	(0.1)
Contribution to consolidated net income – 2015	$10.3	$37.5

EBPC

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. This accounting method has the effect of recognizing higher revenues in the early years of the contract than would have been recorded if the toll revenues were recorded as received.

Income Taxes

EBPC is subject to corporate income tax at the statutory rate of 27.0% (combined Canadian federal and provincial income tax rate).

Emera Energy

Overview

Emera Energy includes the following:

- Emera Energy Services, a wholly owned physical energy marketing and trading business;

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

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

Mark-to-Market Adjustments

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

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

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

Review of 2016 and 2015

Emera Energy Adjusted Contribution to Consolidated Net Income (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures")

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Trading and marketing margin(1)	$ 46.9	$ 38.8	$ 84.9	$117.5	$ 60.3
Electricity sales(2)	180.1	250.9	545.9	520.7	146.2
Total operating revenues – non-regulated	227.0	289.7	630.8	638.2	206.5
Non-regulated fuel for generation and purchased power(3)	114.1	159.9	334.9	384.8	97.9
Operating, maintenance and general	25.3	20.1	79.7	78.7	43.6
Provincial, state and municipal taxes	0.9	1.4	6.6	5.5	0.8

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Depreciation and amortization	10.9	9.3	40.6	37.7	11.2
Total operating expenses	151.2	190.7	461.8	506.7	153.5
Adjusted income (loss) from operations	75.8	99.0	169.0	131.5	53.0
Income from equity investments(4)	3.8	4.0	26.4	12.3	17.1
Other income (expenses), net	(2.6)	22.2	25.1	2.9	0.2
Interest expense, net	6.2	1.0	19.3	6.2	1.0
Adjusted income (loss) before provision for income taxes	70.8	124.2	201.2	140.5	69.3
Income tax expense (recovery)(5)	22.9	47.8	71.1	42.3	24.2
Adjusted contribution to consolidated net income (loss)	$ 47.9	$ 76.4	$130.1	$ 98.2	$ 45.1
After-tax derivative mark-to-market gain (loss)	$ 45.5	$ (11.5)	$ (31.2)	$ 87.5	$ (41.9)
Contribution to consolidated net income	$ 93.4	$ 64.9	$ 98.9	$185.7	$ 3.2
Adjusted contribution to consolidated earnings per common share – basic	$ 0.32	$ 0.53	$ 0.89	$ 0.69	$ 0.34
Contribution to consolidated earnings per common share – basic	$ 0.63	$ 0.45	$ 0.68	$ 1.30	$ 0.02
Adjusted EBITDA	$ 87.9	$134.5	$261.1	$184.4	$ 81.5

(1) Marketing and trading margin excludes a pre-tax mark-to-market gain of Cdn$72.3 million for the quarter ended March 31, 2016 (2015 – Cdn$13.9 million gain). and a loss of Cdn$1.8 million for the year ended December 31, 2015 (2014 – Cdn$119.9 million gain)

(2) Electricity sales exclude a pre-tax mark-to-market loss of Cdn$8.3 million for the quarter ended March 31, 2016 (2015 – Cdn$45.8 million loss) and a loss of Cdn$39.1 million for the year ended December 31, 2015 (2014 – Cdn$42.8 million gain)

(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of Cdn$2.8 million for the quarter ended March 31, 2016 (2015 – Cdn$7.0 million gain) and a loss of Cdn$6.3 million for the year ended December 31, 2015 (2014 – Cdn$20.8 million loss).

(4) Income from equity investments excludes a pre-tax mark-to-market loss of Cdn$2.4 million for the quarter ended March 31, 2016 (2015 – Cdn$3.4 million gain) and a loss of Cdn$5.6 million for the year ended December 31, 2015 (2014 – Cdn$13.2 million loss)

(5) Income tax expense (recovery) excludes an Cdn$18.9 million expense relating to mark-to-market gains for the quarter ended March 31, 2016 (2015 – Cdn$10.0 million recovery) and Cdn$21.6 million recovery relating to mark-to-market losses for the year ended December 31, 2015 (2014 – Cdn$41.2 million expense)

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

	Three months ended March 31
	millions of Canadian dollars
Contribution to consolidated net income – 2015	$ 64.9
Increased marketing and trading margin – See "—Trading and Marketing Margin"	8.1
Decreased electricity sales primarily due to lower hedged and market power prices at the New England Gas Generating Facilities, lower market prices at Bayside Power, and decreased sales volumes at the New England Gas Generating Facilities driven by weather, partially offset by a stronger USD	(70.8)

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

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

Emera Energy's contribution to consolidated net income decreased by Cdn$54.3 million to Cdn$39.7 million in Q4 2015 compared to Cdn$94.0 million in Q4 2014. For the year ended December 31, 2015, Emera Energy's contribution to consolidated net income decreased Cdn$86.8 million to Cdn$98.9 million compared to Cdn$185.7 million in 2014. Highlights of the income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Contribution to consolidated net income – 2013		$ 3.2
Increased trading and marketing margin primarily due to very strong market conditions in northeastern United States and Ontario in Q1 2014 and a stronger USD		57.2
Increased electricity sales primarily due to the acquisition of the New England Gas Generation Facilities in November 2013, higher power prices and increased sales at Bayside Power		374.5
Increased non-regulated fuel for generation and purchased power primarily due to the acquisition of the New England Gas Generation Facilities in November 2013, higher commodity prices and increased generation at Bayside Power		(286.9)
Increased OM&G primarily due to the acquisition of the New England Gas Generating Facilities and increased performance-based compensation accruals resulting from increased trading and marketing margin		(35.1)
Increased depreciation and amortization primarily due to the acquisition of the New England Gas Generation Facilities		(26.5)
Income from equity investments reflects a non-recurring gain on the settlement of warranty obligations related to certain NWP turbines, decreased curtailments at NWP, recognition of business interruption insurance proceeds related to a 2013 outage at Bear Swamp and favourable pricing at Bear Swamp		(4.8)

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Increased income tax expense primarily due to increased income before provision for taxes		(18.1)
Increased mark-to-market gains, net of tax, primarily due to the reversal of 2013 mark-to-market losses and changes in gas and power contract positions, as well as favourable power contracts at the New England Gas Generation Facilities		129.4
Other		(7.2)
Contribution to consolidated net income – 2014	$ 94.0	$ 185.7
Increased (decreased) trading and marketing margin – See "Trading and Marketing Margin"	22.2	(32.6)
Increased electricity sales quarter-over-quarter primarily due to higher sales volumes, reflecting reduced generation for planned outage work at Bridgeport in Q4 2014, which reduced generation and a stronger USD; year-over-year is also partially offset by lower power prices	40.1	25.2
Increased non-regulated fuel for generation and purchased power quarter-over-quarter as a result of higher sales volumes, reflecting reduced generation for planned outage work at Bridgeport in Q4 2014 and a stronger USD; year-over-year reduction is primarily due to lower commodity fuel prices, partially offset by a stronger USD	(24.9)	49.9
Increased OM&G quarter-over-quarter primarily due to timing of maintenance work at the New England Gas Generation Facilities, the stronger USD and increased performance-based compensation resulting from increased trading and marketing margins; year-over year primarily due to stronger USD, offset by decreased performance-based compensation resulting from decreased trading and marketing margins	(8.7)	(1.0)
Increased income from equity investments – See "– Equity Investments"	1.6	14.1
Increased other income (expenses) year-over-year primarily due to a gain on the sale of NWP	0.4	22.2
Increased interest expense, net primarily due to higher interest rates on internal financing	(4.7)	(13.1)
Increased income tax expense primarily due to increased income before provision for income taxes; year-over-year increase also due to changes in the proportion of income earned in higher tax rate foreign jurisdiction and a stronger USD	(8.9)	(28.8)
Decreased mark-to-market, net of tax, quarter-over-quarter primarily due to changes in gas and power contract positions, and amortization of transportation assets; decreased year-over-year also due to the reversal of 2013 mark-to-market losses in 2014	(68.4)	(118.7)
Other	(3.0)	(4.0)
Contribution to consolidated net income – 2015	$ 39.7	$ 98.9

A portion of earnings are exposed to foreign exchange fluctuations thereby impacting adjusted CAD contribution to net earnings. The impact of a stronger USD, quarter-over-quarter, increased earnings in CAD by $3.4 million in Q4 2015 compared to 2014. For the year ended December 31, 2015 the impact of a stronger USD increased earnings in CAD by $11.9 million compared to the same period in 2014.

Energy Services

Emera Energy Services derives revenue and earnings from the wholesale trading and marketing of natural gas, electricity and other energy-related commodities and derivatives within the Company's risk tolerances, including those related to value-at-risk (“VaR”) and credit exposure. Emera Energy purchases and sells physical natural gas and related transportation capacity rights, as well as providing related energy asset management services. Emera Energy Services is also responsible for commercial management of electricity production and fuel procurement for Emera Energy Generation’s fleet. Established in 2002, Emera Energy’s trading and marketing business currently has approximately 80 employees engaged in commercial activities and related back office, legal and other support functions. The primary market for the trading and marketing business is northeastern North America, including the Marcellus shale gas region, the U.S. Gulf Coast and Central Canada. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. Trading and marketing 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. Emera Energy manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

Adjusted EBITDA

Adjusted EBITDA (a non-U.S. GAAP measure described in “Management’s Discussion and Analysis—Non-U.S. GAAP Financial Measures”) for Emera Energy’s trading and marketing business is summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Trading and marketing margin	$46.9	$38.8	$84.9	$117.5	$60.3
OM&G	10.4	7.5	21.3	24.8	15.2
Other income (expenses), net	(3.7)	3.5	5.6	2.6	1.0
Adjusted EBITDA	$32.8	$34.8	$69.2	$ 95.3	$46.1

Trading and Marketing Margin

Trading and marketing margin is comprised of Emera Energy’s corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services’ revenues.

Marketing and trading margin increased Cdn$8.1 million to Cdn$46.9 million in Q1 2016 compared to Cdn$38.8 million in Q1 2015. his increase is primarily due to a stronger USD and growth in the volume of business, including investment in transportation capacity, which offset the impact of sustained low pricing and volatility in several of Emera Energy’s markets in Q1 2016, largely the result of weather. For the year ended December 31, 2015, trading and marketing margin decreased Cdn$32.6 million to Cdn$84.9 million compared to Cdn$117.5 million in 2014. Q1 2014 saw sustained high pricing and volatility in several of Emera Energy’s markets, largely the result of cold weather. Subsequently, there was a return to more normal market conditions. Trading and marketing margins were also favourably affected by the strengthening USD in Q4 2015 and for the year ended December 31, 2015.

Other Income

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

Generation

Emera Energy wholly owns and operates a portfolio of high efficiency, non-utility electricity generating facilities in northeast North America.

Information regarding Emera Energy's wholly owned generation facilities is summarized in the following table:

Wholly Owned Generation Facilities	Location	Capacity (MW)	Commissioning/ In-Service Date	Fuel	Description
New England					
Bridgeport(1)	Connecticut	560	1999	Natural gas	Selling electricity and capacity to ISO-NE
Tiverton	Rhode Island	265	2000	Natural gas	Selling electricity and capacity to ISO-NE
Rumford	Maine	265	2000	Natural gas	Selling electricity and capacity to ISO-NE
Total New England		**1,090**			
Maritime Canada					
Bayside Power	New Brunswick	290	2001	Natural gas	Long-term power purchase agreement ("PPA") November – March; Selling electricity to Maritimes and ISO-NE for remainder of year
Brooklyn Energy	Nova Scotia	30	1996	Biomass	Long-term PPA
Total Maritime Canada		**320**			
Total Emera Energy Generation		**1,410**			

(1) A Q2 2015 upgrade at Bridgeport increased its nameplate capacity from 540 MW to 560 MW.

Emera Energy has approximately 125 employees in its generation business. For the portion of output not committed under PPAs, Emera Energy's generation facilities sell into price-based competitive markets and earn revenues through the physical delivery of power and ancillary services, such as load regulation. The New England facilities also participate in the regional capacity market and are compensated for being available to provide power. The electricity generation business in the northeast is seasonal. Q1, Q3 and Q4 are generally the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season, and cooling load in the summer.

Adjusted EBITDA

Adjusted EBITDA (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures") is summarized in the following tables:

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

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

	Year ended December 31								
	2015	2014	2013	2015	2014	2013	2015	2014	2013
	millions of Canadian dollars (except per share amounts)								
	New England[1]			Maritime Canada[2]			Total		
Energy sales	$413.9	$365.9	$64.0	$88.3	$109.4	$77.8	$502.2	$474.9	$141.8
Capacity and other	43.7	45.8	4.4	—	—	—	43.7	45.8	4.4
Electricity sales	457.6	411.3	$68.4	$88.3	$109.4	$77.8	$545.9	520.7	$146.2
Non-regulated fuel for generation and purchased power	277.3	311.8	48.6	52.2	73.5	47.3	329.5	385.3	95.9
Non-regulated electric margin	180.3	99.5	19.8	36.1	35.9	30.5	216.4	135.4	50.3
Provincial taxes	4.7	4.6	—	0.9	0.9	0.8	5.6	5.5	0.8
OM&G	37.5	29.9	7.1	18.7	21.3	19.3	56.2	51.2	26.4
Other income (expenses), net	1.6		—	(0.7)	0.3	(0.8)	0.9	0.3	(0.8)
Adjusted EBITDA	$139.7	$ 65.0	$12.7	$15.8	$ 14.0	$ 9.6	$155.5	$ 79.0	$ 22.3

(1) The New England Gas Generation Facilities were acquired in November 2013.
(2) Brooklyn Energy was acquired in July 2013.

For the year ended December 31, 2015, adjusted EBITDA increased Cdn$76.5 million to Cdn$155.5 million from Cdn$79.0 million in 2014, primarily due to higher margins realized in the New England Gas Generation Facilities, reflecting favourable short-term economic hedges and favourable pricing. The strengthening USD contributed Cdn$17.6 million.

Operating Statistics

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

(1) Sales volumes represent the actual electricity output of the plants.
(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.
(3) Net capacity factor is the ratio of the utilization of an asset as compared to its maximum capability, within a particular time frame. It is generally a function of plant availability and plant economic vis-à-vis the market.

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

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

	Year ended December 31					
	2015	2014	2015	2014	2015	2014
	millions of Canadian dollars (except per share amounts)					
	Sales Volumes (GWh)(1)		Plant Availability(2)		Net Capacity Factor (%)(3)	
New England	4,777	4,375	94.5%	79.9%	50.5%	47.6%
Maritime Canada	1,699	1,910	92.7%	91.4%	61.9%	69.9%
Total	6,476	6,285	94.1%	82.6%	53.0%	52.7%

(1) Sales volumes represent the actual electricity output of the plants.

(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.

(3) Net capacity factor is the ratio of the utilization of an asset as compared to its maximum capability, within a particular time frame. It is generally a function of plant availability and plant economics vis-à-vis the market.

Year-over-year increase in sales volumes was primarily due to fewer outage days in 2015 at the New England Gas Generation Facilities.

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

Equity Investments

Information regarding Emera Energy's equity investments in generation facilities is summarized below:

Investments in Generation Facilities	Ownership	Location	Capacity (MW)	Fuel	Description
New England					
Bear Swamp	50%	Massachusetts	600	Hydro	Long-term PPA and selling electricity and capacity to ISO-NE
NWP(1)	49%	Maine	419	Wind	Long-term PPA and selling electricity and capacity to ISO-NE and New York ISO
Total New England			**1,019**		

(1) On January 29, 2015, Emera completed the sale of NWP to First Wind for $223.3 million USD. Emera's carrying value of its 49% interest as at December 31, 2014 was $204.4 million USD.

Adjusted income from equity investments

Adjusted income from equity investments (a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures") is summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013(1)
	millions of Canadian dollars (except per share amounts)				
Bear Swamp	$ 3.8	$2.1	$24.5	$19.2	$15.8
NWP	—	1.9	1.9	(6.9)	1.3
Adjusted Income from equity investments	$ 3.8	$4.0	$26.4	$12.3	$17.1

Income from equity investments decreased Cdn$0.2 million to Cdn$3.8 million in Q1 2016 compared to Cdn$4.0 million in Q1 2015, largely due to the sale of NWP in Q1 2015 and higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing, largely offset by favourable pricing at Bear Swamp and the effect of a stronger USD. For the year ended December 31, 2015, adjusted income from equity investments increased Cdn$14.1 million to Cdn$26.4 million compared to Cdn$12.3 million in 2014. This was primarily due to the resupply of the contracted power sales in Bear Swamp in 2015 that were not delivered in 2014 due to transmission line outages, NWP losses recorded in 2014 and the strengthening USD.

Other Income

On January 29, 2015, Emera completed the sale of its 49% interest in NWP for Cdn$282.3 million ($223.3 million USD). This sale resulted in a pre-tax gain of Cdn$18.6 million or Cdn$0.13 per common share (after-tax gain of Cdn$11.5 million or Cdn$0.08 per common share), which was recorded in "Other income (expenses), net" on the Consolidated Statements of Income in Q1 2015.

Income Taxes

Emera Energy is subject to corporate income tax at the statutory rate ranging from 39.2 to 41.5% (combined U.S. federal and state income tax rate) on its U.S. sourced income and ranging from 27.0 to 31.0% (combined Canadian federal and provincial income tax rate) on its Canada sourced income.

New England Gas Generation Facilities is subject to corporate income tax at the statutory rate ranging from 35.0 to 40.9% (combined U.S. federal and state income tax rate).

Brooklyn Energy is subject to corporate income tax at the statutory rate of 31.0% (combined Canadian federal and provincial income tax rate).

Bear Swamp Refinancing

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at fixed rate of 4.89% and $25 million USD at a floating rate of LIBOR plus 2.70%. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $178.7 million ($137.3 million USD) non-taxable distribution in Q4 2015.

Corporate and Other

Corporate

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

Other

Other includes the following consolidated and non-consolidated investments:

Consolidated Investments

- Emera Utility Services is a utility services contractor primarily operating in Atlantic Canada (recorded in "Non-regulated operating revenue" in the table below).
- Emera Reinsurance Limited is a captive insurance company providing insurance and reinsurance to Emera and certain of its affiliates, to enable more cost efficient management of risk and deductible levels across Emera (recorded in "OM&G" and "Other income (expenses), net" in the table below).

Non-consolidated investments **(recorded in "Income (loss) from equity investments" in the table below)**

- Emera's 19.4% investment in APUC, a diversified generation, transmission and distribution utility traded on the Toronto Stock Exchange under the symbol "AQN." The distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American-based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate-regulated electric transmission and natural gas pipeline systems in the United States and Canada. The investment in APUC is accounted for on an equity basis. As at March 31, 2016, Emera owned 50.1 million common shares, 12.9 million outstanding subscription receipts and dividend equivalents, at an average conversion price of Cdn$9.19. The outstanding subscription receipts and dividend equivalents will automatically convert to common shares in Q4 2016, if an election is not made. On May 17, 2016 Emera announced that it had agreed to sell all of the 50.1 million common shares it held in APUC, representing approximately 19.3% of APUC's issued and outstanding common shares, to a syndicate of underwriters at Cdn$10.85 per common share for aggregate gross proceeds of approximately Cdn$544 million. The sale was completed on May 24, 2016. Emera continues to hold the subscription receipts and associated dividend equivalents, which represent approximately 4.75% of APUC's issued and outstanding common shares (after giving effect to the conversion of the subscription receipts and associated dividend equivalents).
- Emera's 100% investment in ENL, which holds investments in the following:
  - Emera's 100% investment in NSPML, a Cdn$1.56 billion transmission project, including two 170-kilometre subsea cables, between the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the return on equity component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017.
  - Emera's 59.0% (December 31, 2015 – 55.1%) investment in the partnership capital of LIL, a Cdn$3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49% of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017.
- Other investments.

Mark-to-Market Adjustments

Specific to the Acquisition, Emera has recorded after-tax mark-to-market losses of Cdn$121.1 million for the three months ended March 31, 2016 (2015 – nil) and after tax mark-to-market gains of Cdn$100.5 million for the year ended December 31, 2015 (2014 – nil) related to the effect of USD-denominated currency and forward contracts put in place to hedge the anticipated proceeds from the Final Instalment of the Convertible Debenture Offering of the pending acquisition, expected to close mid-2016.

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

Review of 2016 and 2015

Corporate and Other

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Intercompany revenue[(1)]	$ 9.9	$ 5.3	$ 34.2	$ 26.0	$ 38.3
Non-regulated operating revenue	8.4	8.8	40.1	48.7	43.5
Non-regulated direct costs	8.2	9.7	42.4	46.9	44.6
Operating, maintenance and general	13.7	12.7	104.1	46.2	39.0
Depreciation and amortization	0.7	0.3	1.7	2.3	3.8
Total operating expenses	22.6	22.7	148.2	95.4	87.4
Income (loss) from operations	(4.3)	(8.6)	(73.9)	(20.7)	(5.6)
Income (loss) from equity earnings	18.1	11.9	61.3	46.3	3.3
Other income (expenses), net[(2)]	3.6	(0.2)	(4.3)	3.2	16.9
Interest expense	33.1	6.3	48.1	30.9	37.5
Adjusted income (loss) before provision for income taxes[(4)]	(15.7)	(3.2)	(65.0)	(2.1)	(22.9)
Income tax expense (recovery)[(3)]	(13.7)	(7.9)	(40.1)	(20.6)	(28.4)
Preferred stock dividends	7.0	7.7	30.3	26.2	19.3
Adjusted contribution to consolidated net income[(4)]	$ (9.0)	$ (3.0)	$ (55.2)	$ (7.7)	$(13.8)
After-tax mark-to-market gain (loss)	(121.1)	—	100.5	—	—
Contribution to consolidated net income	$(130.1)	$ (3.0)	$ 45.3	$ (7.7)	$(13.8)
Adjusted contribution to consolidated earnings per common share – basic[(4)]	$ (0.06)	$(0.02)	$ (0.38)	$(0.05)	$(0.10)
Contribution to consolidated earnings per common share – basic	$ (0.87)	$(0.02)	$ 0.31	$(0.05)	$(0.10)
Adjusted EBITDA[(4)]	$ 18.1	$ 3.4	$ (15.2)	$ 31.1	$ 18.4

(1) Intercompany revenue consists of interest from EBPC, M&NP and Emera Energy Generation.

(2) Other income (expenses) net, excludes a pre-tax mark-to-market loss of $139.5 million in Q1 2016 compared to nil for the same period in 2015 and a pre-tax mark-to-market gain of $118.9 million for the year ended December 31, 2015 (2014-nil).

(3) Income tax expense (recovery), excludes an $18.4 million recovery relating to mark-to-market losses in Q1 2016 compared to nil for the same period in 2015 and an $18.4 million expense for the year ended December 31, 2015 (2014 – nil).

(4) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures."

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

	Three months ended March 31
	millions of U.S. dollars
Contribution to consolidated net income – 2015	$ (3.0)
Increased intercompany revenue primarily due to the issuance of a loan to Emera Energy Generation	4.6
Income from equity investments – see table entitled "Contribution to consolidated net income – 2013"	6.2
Increased interest expense primarily due to interest on the Acquisition-related convertible debentures represented by instalment receipts	(26.8)
Increased income tax recovery primarily due to decreased income before provision for income taxes	5.8
After-tax mark-to-market gain (loss) – see "After-Tax Mark-to-Market Gain (Loss)"	(121.1)
Other	4.2
Contribution to consolidated net income – 2016	$(130.1)

For the year ended December 31, 2015, Corporate and Other's contribution to consolidated net income increased Cdn$53.0 million to Cdn$45.3 million compared to Cdn$(7.7) million in 2014. Highlights of the income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Contribution to consolidated net income – 2013		**$ (13.8)**
Decreased intercompany revenue primarily due to lower interest revenue resulting from the repayment of NWP loan in November 2013		(12.3)
Increased OM&G primarily due to higher deferred compensation costs, partially offset by lower business development costs		(7.2)
Income from equity investments – see "– Income from Equity Investments"		43.0
Decreased other income primarily due to the 2013 gains on the exchange of APUC subscription receipts to common shares, partially offset by the 2013 AHI investment impairment		(13.7)
Decreased interest expense primarily due to lower short-term debt levels		6.6
Increased income tax expense primarily due to increased income before provision for income taxes		(7.8)
Increased preferred stock dividends primarily due to an incremental preferred share issuance		(6.9)
Other		4.4
Contribution to consolidated net income – 2014	$ 0.8	$ (7.7)
Increased intercompany revenue due to the issuance of a loan to Emera Energy Generation, partially offset by the repayment of an intercompany loan from EBPC	3.1	8.2
Acquisition costs related to the Acquisition	(21.0)	(51.5)
Decreased OM&G quarter-over-quarter primarily due to lower performance-based compensation; increased year-over-year primarily due to business development costs not related to the Acquisition	5.1	(6.4)
Income from equity investments – see Income from Equity Investments section below	13.9	15.0

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Decreased other income quarter-over-quarter due to the reclassification of APUC subscription receipts; year-over-year due to the losses incurred in Emera Reinsurance from Tropical Storm Erika and the recognition of NSPML as an equity investment in Q2 2014	(4.9)	(7.5)
Increased interest expense primarily due to interest on convertible debentures represented by installment receipts, partially offset year-over-year by maturity of long-term debt in Q4 2014	(23.2)	(17.2)
Decreased income tax expense primarily due to the decreased income before provision for income taxes	10.3	19.5
Increased preferred stock dividends year-over-year primarily due to issuance of preferred shares in Q2 2014	—	(4.1)
After-tax mark-to-market gain (loss) – see "After-Tax Mark-to-Market Gain (Loss)"	100.5	100.5
Other	(1.1)	(3.5)
Contribution to consolidated net income – 2015	$ 83.5	$ 45.3

Acquisition-Related Costs

Highlights of the Acquisition-related costs are summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014	2013
	millions of Canadian dollars (except per share amounts)				
Operating, maintenance, and general	$ 0.1	$—	$ 51.5	—	$—
Interest expense, net	25.5	—	23.9		—
Income tax expense (recovery)	(8.1)	—	(22.6)		—
Acquisition-related costs	$17.5	$—	$ 52.8	$—	$—

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

The foreign currency earnings impact related to the translation from the convertible debenture USD cash balance and the mark-to-market adjustments from forward contracts from economically hedging the Convertible Debenture Offering are recorded as a mark-to-market adjustment. These pre-tax losses totaled Cdn$139.5 million in Q1 2016 and are recorded in "Other income (expenses), net" on the Consolidated Statements of Income (Cdn$121.1 million after-tax loss). These losses offset a pre-tax mark-to-market gain of Cdn$118.9 million (Cdn$100.5 million after-tax gain) recorded in Q4 2015. The after-tax mark-to-market gain (loss) is summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014[(1)]	2013[(1)]
	millions of Canadian dollars (except per share amounts)				
Foreign exchange on USD cash	$ (44.7)	$—	$ 26.8	—	$—
Mark-to-market adjustment on USD forward contracts	(94.8)	—	92.1		—
Income tax expense (recovery)	18.4	—	(18.4)		—
After-tax mark-to-market gain (loss)	$(121.1)	$—	$100.5	$—	$—

Income from Equity Investments

Income from equity investments are summarized in the following table:

	Three months ended March 31		Year ended December 31		
	2016	2015	2015	2014[(1)]	2013[(1)]
	millions of Canadian dollars (except per share amounts)				
APUC	$ 9.0	$ 6.6	$36.9	30.4	$ 0.4
NSPML	4.4	3.6	14.9	9.5	—
LIL	4.7	1.7	9.5	6.4	5.2
AHI	—	—	—	—	(2.3)
Income from equity investments	$18.1	$11.9	$61.3	$46.3	$ 3.3

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

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

Income from equity investments increased Cdn$13.9 million to Cdn$25.5 million in Q4 2015 compared to Cdn$11.6 million in Q4 2014. For the year ended December 31, 2015, income from equity investments increased Cdn$15.0 million to Cdn$61.3 million compared to Cdn$46.3 million in 2014. Highlights of the income changes are summarized in the following table:

	Three months ended December 31	Year ended December 31
	millions of Canadian dollars	
Income from equity investments – 2013		$ 3.3
APUC – Increased due to dilution gains resulting from share issuances, higher earnings and 2013 recognition of discontinued operations of $8.3 million		30.0
NSPML – Recognition of the AFUDC earnings of NSPML as income from equity investment		9.5
Other		3.5
Income from equity investments – 2014	$11.6	$46.3
APUC – Increased quarter-over-quarter primarily due higher equity earnings in 2015, the reclassification of APUC subscription receipts in 2015 and a higher dilution gain from the share issuance in Q4 2015 compared to dilution gain from share issuance in Q4 2014; year-over-year due to higher equity earnings in 2015, the reclassification of APUC subscription receipts in 2015, partially offset by lower dilution on APUC share issuances in 2015 compared to dilutions related to share issuances in 2014	12.4	6.5
NSPML – Increased year-over-year due to the recognition of the AFUDC earnings of NSPML as income from equity investment	(0.6)	5.4
LIL – Increase in investment	2.1	3.1
Income from equity investments – 2015	$25.5	$61.3

NSPML has invested Cdn$796.7 million as at March 31, 2016 of equity, debt and working capital, including Cdn$90.3 million of AFUDC, in the development of the Maritime Link Project. Project to date, Emera has invested a total of Cdn$206.4 million in equity, which is comprised of Cdn$169.3 million in equity contributed and Cdn$37.1 million of accumulated retained earnings, with the remaining costs being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9%. Proceeds from the federally guaranteed debt financing completed in April 2014, were used to fund project costs until the Project's target debt to equity ratio reached 70% to 30% respectively, in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70% and 30% ratio, with equity contributions of Cdn$14.4 million in Q1 2016.

Emera has invested Cdn$250.4 million in the LIL as at March 31, 2016, which is comprised of Cdn$224.5 million in equity contributed and Cdn$25.9 million of accumulated equity earnings. Equity earnings are being recorded based on an annual rate 8.8% of the equity invested. The rate is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities.

Liquidity and Capital Resources

The Company generates cash primarily through its investments in various regulated and non-regulated energy related entities and investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in Emera's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries maintain solid credit metrics and are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the three months ended March 31, 2016 and 2015 include:

	2016	2015	$ Change
	millions of Canadian dollars		
Cash and cash equivalents, beginning of period	$1,073.4	$ 221.1	$ 852.3
Provided by (used in):			
Operating cash flow before change in working capital	232.4	257.5	(25.1)
Change in working capital	(51.8)	(137.9)	86.1
Operating activities	180.6	119.6	61.0
Investing activities	(139.3)	195.9	(335.2)
Financing activities	(45.8)	(259.3)	213.5
Effect of exchange rate changes on cash and cash equivalents	(69.4)	28.0	(97.4)
Cash and cash equivalents, end of period	$ 999.5	$ 305.3	$ 694.2

Significant changes in the statements of cash flows between the years ended December 31, 2015 and 2014 include:

	Year ended December 31		
	2015	2014	$ Change
	millions of Canadian dollars		
Cash and cash equivalents, beginning of period	$ 221.1	$ 100.8	$ 120.3
Provided by (used in):			
Operating cash flow before changes in working capital	775.8	716.3	59.5
Change in working capital	(101.6)	46.2	(147.8)

	Year ended December 31		
	2015	2014	$ Change
	millions of Canadian dollars		
Operating activities	674.2	762.5	(88.3)
Investing activities	(123.7)	(710.9)	587.2
Financing activities	221.1	58.2	162.9
Effect of exchange rate changes on cash and cash equivalents	80.7	10.5	70.2
Cash and cash equivalents, end of period	$1,073.4	$ 221.1	$ 852.3

Operating Cash Flows

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

Investing Cash Flows

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

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

Details of the capital spend are shown below:

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

Net cash used in investing activities decreased Cdn$587.2 million to Cdn$123.7 million for the year ended December 31, 2015 compared to Cdn$710.9 million for the year ended December 31, 2014. The decrease was primarily due to proceeds from the sale of NWP in 2015, proceeds from the Bear Swamp distribution, purchase of APUC subscription receipts in 2014 and higher levels of investment in NSPML and M&NP in 2014, partially offset by increased capital spend and Emera Maine's investment in a customer information system.

Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2015 were Cdn$436 million compared to Cdn$462 million in 2014 primarily due to decreased capital spending in Emera Energy and Emera Maine, partially offset by increased capital spending at Emera Caribbean. Details of the capital spend are shown below:

- Cdn$274 million in NSPI (2014 – Cdn$274 million);
- Cdn$66 million in Emera Maine (2014 – Cdn$85 million);
- Cdn$44 million in Emera Caribbean (2014 – Cdn$30 million);
- Cdn$42 million in Emera Energy (2014 – Cdn$63 million);
- Cdn$10 million in Corporate and Other (2014 – Cdn$10 million)

Financing Cash Flows

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

Net cash provided by financing activities increased Cdn$162.9 million to Cdn$221.1 million for the year ended December 31, 2015 compared to Cdn$58.2 million in December 31, 2014. The increase was primarily due to the proceeds of Convertible Debentures represented by instalment receipts related to the pending Acquisition, net of issuance costs, of Cdn$681.4 million and the proceeds of the long-term debt issuance by EBPC and NSPI. This was partially offset by the redemption of NSPI's preferred shares, repayment of debt in 2015 and the issuance of common and preferred stock in Q1 2014.

Working Capital

As at December 31, 2015, Emera's cash and cash equivalents were Cdn$1,073.4 million (2014 – Cdn$221.1 million) and Emera's investment in non-cash working capital was Cdn$599.2 million (2014 – Cdn$358.3 million). Of the Cdn$1,073.4 million of cash and cash equivalents held at December 31, 2015, Cdn$727.6 million is from the proceeds from the Convertible Debentures for the Acquisition and are held in USD. Of the remaining cash and cash equivalents, Cdn$373.2 million is held by Emera's foreign subsidiaries (2014 – Cdn$206.0 million). A portion of these funds are invested in countries that have certain exchange controls, required approvals, and processes for repatriation. Such funds remain available to fund local operating and capital requirements unless repatriated.

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 debt and equity capital markets.

Contractual Obligations

As at March 31, 2016, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

	2016	2017	2018	2019	2020	Thereafter	Total
			millions of Canadian dollars				
Long-term debt	$ 268.8	$ 49.5	$ 23.8	$ 610.1	$ 748.5	$2,301.2	$ 4,001.9
Purchased power[1]	166.5	229.8	204.0	198.7	195.2	2,380.5	3,374.7
Solid fuel supply	114.5	75.7	12.0	—	—	—	202.2
DSM	22.1	34.0	34.9	—	—	—	91.0
Pension and post-retirement obligations[2]	11.1	19.2	19.8	20.2	20.9	716.7	807.9
Asset retirement obligations	5.1	4.0	4.3	4.2	1.7	317.2	336.5
Interest payment obligations[3]	140.0	177.4	175.1	167.7	138.8	2,244.7	3,043.7
Convertible debentures represented by instalment receipts[4]	727.6	—	—	—	—	—	727.6
Interest obligations on the first instalment of convertible debentures represented by instalment receipts[4]	54.1	—	—	—	—	—	54.1
Transportation[5]	188.9	118.6	78.2	43.2	41.1	86.3	556.3

	2016	2017	2018	2019	2020	Thereafter	Total
				millions of Canadian dollars			
Long-term service agreements[(6)]	48.6	49.6	34.4	47.1	20.4	202.1	402.2
Capital projects	69.2	5.6	—	—	—	—	74.8
Equity investment commitments[(7)]	356.0	183.0	—	—	—	—	539.0
Leases and other[(8)]	18.9	9.9	9.0	8.4	7.3	19.0	72.5
	$2,191.4	$956.3	$595.5	$1,099.6	$1,173.9	$8,267.7	$14,284.4

(1) Annual requirement to purchase 20 to 100% of electricity production from independent power producers over varying contract lengths up to 25 years.

(2) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2015. Credited service and earnings are assumed to be crystallized as at December 31, 2015. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over as at December 31, 2015 to be eligible. As the defined benefit pension plans currently undergoes regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(3) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at March 31, 2016, including any expected required payment under associated swap agreements.

(4) In 2015, to finance a portion of the pending Acquisition, Emera completed the sale of the Convertible Debentures. The Convertible Debentures were sold on an instalment basis, with 1/3 paid on closing of the Convertible Debenture Offering, and the remaining payable on a date to be fixed following satisfaction of conditions precedent to the closing of the Acquisition.

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

(6) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.

(7) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty percent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to the Labrador Island Link Limited Partnership upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amounts as the projects advance through construction.

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

Other Contractual Obligations

On September 4, 2015, the Company announced a definitive agreement for Emera to acquire TECO Energy for $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.6 billion USD and includes the assumption of approximately $4.1 billion USD of debt. Further information on the pending Acquisition is discussed in the Developments section.

Forecasted Gross Consolidated Capital Expenditures

For the year ended December 31, 2016, forecasted gross consolidated capital expenditures are as follows:

	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Total
	millions of Canadian dollars (except per share amounts)					
Generation	$105.0	$ —	$ 17.9	$29.9	$ —	$152.8
New renewable generation	—	—	67.3	—	—	67.3

	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Total
	millions of Canadian dollars (except per share amounts)					
Transmission	56.1	33.6	5.9	—	—	95.6
Distribution	74.8	34.3	38.3			147.4
Facilities, equipment, vehicles, and other	44.0	17.2	20.1		20.4	101.7
	$279.9	$85.1	$149.5	$29.9	$20.4	$564.8

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately Cdn$1.3 billion committed syndicated revolving bank lines of credit per the table below. NSPI has an active commercial paper program for up to Cdn$500 million, of which the full amount outstanding is backed by NSPI's operating credit facility referred to below. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

As at March 31, 2016, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
		millions of dollars		
Emera – Operating and acquisition credit facility	June 2020 – Revolver	$700	$276	$424
NSPI – Operating credit facility	October 2020 – Revolver	600	386	114
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	21	59
Other – in USD – Operating credit facilities	Various	32	2	30

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at March 31, 2016.

For the purpose of bridge financing for the pending Acquisition, on September 4, 2015, the Company secured an aggregate of $6.5 billion USD non-revolving term credit facilities from a syndicate of banks. The non-revolving term credit facilities are comprised of a $4.3 billion USD debt bridge facility, repayable in full on the first anniversary following its advance, and a $2.2 billion USD equity bridge facility repayable in full on the first anniversary following its advance. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the First Instalment of the Convertible Debentures and the proceeds from the Bear Swamp financing. The credit facilities table above does not include the Acquisition Credit Facilities.

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

Emera's future liquidity and capital needs, not including the capital needs to fund the Acquisition, will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, potential new acquisitions, dividends and debt servicing. These liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets.

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) the proceeds from the Acquisition Capital Markets Transactions, including any series of Notes offered hereunder, (ii) the receipt of payment in full on the Final Instalment Date of the Final Instalment due under the Convertible Debentures, (iii) amounts drawn under the Acquisition Credit Facilities, if any, and (iv) existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) and other sources available to Emera.

Emera and its subsidiaries recent financing activity is discussed further in the Developments section of the MD&A.

Share Capital

Emera

As at December 31, 2015, Emera had 147.21 million (2014 – 143.78 million) common shares issued and outstanding. For the year ended December 31, 2015, 3.43 million common shares were issued (2014 – 10.89 million) for net proceeds of Cdn$141.1 million (2014 – Cdn$313.4 million). The issuance of shares was primarily due to facilitate the creation and issuance of depositary receipts in connection with the ECI share acquisition and the dividend reinvestment program.

On December 17, 2015, Emera issued 1.25 million common shares to facilitate the creation and issuance of 5.0 million depositary receipts in connection with the ECI share acquisition.

As at December 31, 2015, Emera had 29.0 million preferred shares issued and outstanding (2014 – 29.0 million).

Pension Funding

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2016 for defined benefit pension plans is expected to be Cdn$19.7 million (2015 – Cdn$ 23.0 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds and short- term investments. Emera reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

Emera's projected contributions to defined contribution pension plans are Cdn$10.0 million for 2016 (2015 – Cdn$9.0 million actual).

Defined Benefit Pension Plan Summary

As at December 31, 2015

millions of Canadian dollars

Plans by region	NSPI Pension Plans	Emera Maine Pension Plans	Caribbean Plans	Total
Assets as at December 31, 2015	$1,128.6	$161.5	$10.3	$1,300.4
Accounting obligation at December 31, 2015	1,295.8	211.3	12.6	1,519.7
Accounting expense during fiscal 2015	$ 56.1	$ 6.4	$ 0.4	$ 62.9

Off-Balance Sheet Arrangements

Defeasance

Upon privatization of the former provincially owned NSPC in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2015 totaled Cdn$0.8 billion (2014 – Cdn$0.7 billion). The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. Approximately 70% of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

Under the privatization agreements, NSPI administers the defeasance cash flows and obligations pursuant to a Management and Administration Agreement. The NSPFC bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement and therefore, from time to time, if any cash accumulates in the NSPFC bank account it is available as an offset until that cash is required to service the defeased NSPC debt.

Guarantees and Letters of Credit

Emera had outstanding the following guarantees and letters of credit on behalf of third parties which are not included within the Consolidated Balance Sheets as at December 31, 2015:

- Emera has provided a completion guarantee to the Government of Canada, whereby it has guaranteed the performance of the obligations of NSPML to cause the completion of the Maritime Link Project, subject to certain conditions set out in that guarantee. The cost of those obligations is estimated to be Cdn$1.577 billion, which reduces in the ordinary course as project costs are paid.
- Emera has provided a guarantee to the Long Island Power Authority on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement with the Long Island Power Authority, which expires on April 30, 2021. The guarantee is for 50% of the relevant obligations under the PPA up to a maximum of $5.1 million USD. As at December 31, 2015, the fair value of the PPA was positive.
- Standby letters of credit in the amount of $20.5 million USD for the benefit of secured parties in connection with a refinancing of the Bear Swamp joint venture and also to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.
- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2016 and is renewed annually. The amount committed as at December 31, 2015 was Cdn$42.6 million.

- A standby letter of credit to secure obligations under an unfunded pension plan in Emera Maine. The letter of credit expires in October 2016 and is renewed annually. The amount committed as at December 31, 2015 was $2.7 million USD.
- A standby letter of credit was issued to secure the obligations of Emera Reinsurance Limited under reinsurance agreements. The letter of credit expires in February 2016. The amount committed as at December 31, 2015 was $2.0 million USD.

Outlook

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

Among the key trends influencing Emera's long-term strategy is the increasing expectation by customers and policy-makers for a permanent reduction in the carbon-equivalent levels of electricity generation. This advocacy drive for cleaner, renewable sources of electricity has become a defining trend in the industry in recent years, not just in the markets Emera serves, but on a global basis. While it is still unclear whether economic volatility and lower fossil fuel prices will slow the pace of this transformation, its impact on the sector continues to be felt in the form of mandated and incented carbon reductions throughout eastern North America and in the Caribbean. As such, investment in wind and hydro generation, and natural gas infrastructure, is likely to continue across the sector.

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

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

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

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

Business Outlook

The Acquisition will result in further acquisition costs in 2016. The Acquisition is expected to be accretive to EPS by approximately 5% in the first full year following its completion (2017), growing to more than 10% by the third full year (2019) assuming a USD/CAD exchange rate consistent with that at the time of announcement. Approximately 95% of the expected foreign exchange exposure to close the pending acquisition has been effectively hedged.

Emera's operations are affected by the U.S. dollar relative to the Canadian dollar. With the disparity between the two currencies, the effect on Emera's income is noteworthy, as approximately 50% of Emera's adjusted net income was derived from subsidiaries with a U.S. functional currency. TECO Energy operations are conducted in U.S. dollars and following the pending acquisition, Emera's consolidated net income and cash flows will be impacted to a greater extent by movements in the U.S. dollar relative to the Canadian dollar.

NSPI

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

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

Over the past several years, the requirement to reduce Nova Scotia's reliance upon high carbon and greenhouse gas emitting sources of energy has resulted in NSPI making a significant investment in renewable energy sources and purchasing third party renewable energy. In December 2015, the Electricity Plan Act was enacted by the Province of Nova Scotia, with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. In accordance with the Electricity Plan Act, NSPI filed a three-year rate plan with the UARB for Fuel Costs in Q1 2016, which requested average annual rate increases of 1.3% for 2017 through 2019. NSPI also announced that it will not file a general rate application for non-fuel costs for the 2017 to 2019 period. This was a result of NSPI continuing to work towards rate stability for customers through a focused effort on operating costs, productivity levels and service improvements.

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

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

Emera Maine

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

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

Emera Maine has an agreement with Central Maine Power Company to pursue specific transmission opportunities in northern Maine that would relieve transmission congestion and more efficiently collect and deliver wind to southern New England markets. As part of this agreement, Emera Maine and Central Maine Power Company jointly responded in Q1 2016 to a request for proposals from Massachusetts, Connecticut and Rhode Island. The demand for new renewable energy, and the infrastructure to deliver that energy to market, is growing as a result of increasing renewable portfolio requirements of the southern New England states.

There are three outstanding pending complaints, with the FERC, to challenge the ISO-New England Open Access Transmission Tariff-allowed base ROE. On March 22, 2016, the Administrative Law Judge ("ALJ") issued a recommended decision to the FERC with respect to the first two outstanding ROE complaints. The ALJ recommendation for the ENE Case was a 9.59% base ROE, with a 10.42% maximum ROE, and the recommendation for MA AG II Case was a 10.90% base ROE, with a 12.19% maximum ROE. A reserve was calculated on a 10.57% base and represents Emera Maine's best estimate of the probable outcome for the two outstanding complaints, and no update was made to the reserve based on the ALJ recommendation, as it is pending approval by the FERC and considered uncertain until that time. On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"), a collection of thirteen municipal light departments, seeking to reduce the base transmission ROE to a maximum of 8.93% and the maximum ROE of 11.24%. No reserve has been made as a result of this complaint, as the outcome is considered uncertain.

In 2016, Emera Maine expects to invest approximately Cdn$89.5 million (2015 – Cdn$66 million actual), including approximately Cdn$42.9 million for transmission projects.

Emera Caribbean

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

The Barbados economy is forecasted to grow modestly in 2016. With oil being the predominant fuel source for generation of electricity in the Caribbean, reduced oil prices may result in an economic benefit on the island in decreased cost of electricity to ratepayers.

The economy of Grand Bahama is highly correlated to the United States economy. In 2015, the economy of Grand Bahama exhibited signs of improving with economic growth in the industrial sector and weather related growth in the residential sector. 2016 sales are expected to be flat compared to 2015.

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

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

Pipelines

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

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

Emera Energy

Emera Energy Services

Emera Energy Services, Emera Energy's marketing and trading business, is generally dependent on market conditions. In particular, volatility in electricity and natural gas markets, which can be influenced by weather, local supply constraints and other supply/demand factors, can provide higher levels of margin opportunity.

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

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

Emera Energy Generation

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

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

In addition to energy margins and ancillary revenue, the New England Gas Generating Facilities and Bear Swamp earn revenue from capacity payments through the forward capacity market, the annual reconfiguration capacity market and the monthly reconfiguration capacity market. Prices for the forward capacity market, the larger of the two components, are determined through an auction process held annually, three years in advance, providing revenue visibility to 2020, presuming the facilities continue to be available to support their capacity obligations. Details of pricing and estimated revenues are outlined in the table below for the New England Gas Generating facilities, and Emera Energy's 50% interest in Bear Swamp.

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

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

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

In 2016, Emera Energy expects to invest approximately Cdn$41.0 million (2015 – Cdn$42.0 million actual) in capital projects related to its generating assets in order to further improve reliability and increase plant capacity.

Corporate and Other

Corporate and Other is dependent, in part, on business development and acquisition-related initiatives, which in 2016 will include further costs related to the Acquisition, AFUDC earnings as a result of equity investments in the Maritime Link Project and the Labrador-Island Link, project-based construction services activity by Emera Utility Services, growth in APUC earnings (which Emera accounts one quarter after APUC reports such earnings), corporate financing costs and other corporate activities.

Corporate's contribution to consolidated net income in 2016 is expected to be lower than 2015 primarily due to further acquisition costs and associated financing initiatives related to the Acquisition. These costs will include a non-cash accounting charge for the difference between Emera's closing share price on the issuance date of the Convertible Debentures and their exercise price. This will be recognized once contingencies surrounding regulatory and other approvals are resolved.

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

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

ENL

NSP Maritime Link Inc. ("NSPML")

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

ENL's future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for design and construction activities, which will determine the component of costs to be funded by equity. Proceeds from the federally guaranteed debt financing completed in 2014 were used to fund project costs until the Project's debt to equity ratio reached 70% to 30% respectively in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70% to 30% ratio, with equity contributions of Cdn$14.4 million in Q1 2016.

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

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, currently estimated at approximately Cdn$3.1 billion. As at March 31, 2016, ENL has invested Cdn$250.4 million, comprised of Cdn$224.5 million in equity contributed and Cdn$25.9 million of accumulated equity earnings in LIL. Equity earnings are recorded based on an annual rate of 8.8% of the equity invested. The return on ROE is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB"). There is currently an application filed by another regulated electrical utility in Newfoundland and Labrador, being heard by the NLPUB, which includes a review of ROE. The NLPUB's decision on ROE, expected in Q2 2016, will be applicable for all regulated electrical utilities in Newfoundland and Labrador and become the ROE applicable to ENL's investment in LIL. Future earnings are dependent on the amount and timing of additional equity investments and the approved ROE. Total equity contributions for Q1 2016 for LIL were Cdn$38.4 million.

LIL forecasted equity contributions for 2016 and 2017 are Cdn$196.0 million and Cdn$27.0 million respectively, with total equity investment, by Emera, in the Project estimated to be Cdn$409.1 million.

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

Transactions with Related Parties

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate- regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. 2014 balances have been retrospectively restated, consistent with this approach. Below are transactions between Emera and its associated companies reported in the Consolidated Statements of Income:

			Three months ended March 31	
	Nature of Service	Presentation	2016	2015
			millions of Canadian dollars	
Sales to:				
APUC subsidiary	Net sale of natural gas and transportation	Operating revenue – non-regulated	$ 2.0	$ 1.6
Purchases from:				
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	0.3	$ 0.2
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	$(8.1)	$(6.3)

Operating revenue—non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate- regulated subsidiaries of Emera totaling Cdn$0.3 million for the three months ended March 31, 2016 (2015 – Cdn$(0.2) million).

			Year ended December 31	
	New England	Maritime Canada	2015	2014
			millions of Canadian dollars	
Sales to:				
APUC subsidiary	Net sale of natural gas and transportation	Operating revenue – non-regulated	$ 3.0	$ 4.4
NWP	Energy management services	Operating revenue – regulated	0.3	1.1
Purchases from:				
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	4.5	3.6
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	(23.4)	(23.8)
NWP	Purchase of power	Regulated fuel for generation and purchased power	$ 0.3	$ 1.9

Operating revenue—non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate- regulated subsidiaries of Emera totaling Cdn$1.6 million for the year ended December 31, 2015 (2014 – Cdn$4.2 million).

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

	March 31 2016	December 31 2015
	millions of Canadian dollars	
Due from related parties:		
NSPML – current	$1.2	$1.6
Subsidiary of APUC – current	0.3	0.7
M&NP – loan receivable – long-term	2.5	2.5
Due to related parties:		
M&NP – current	2.3	2.1
Net due from (to) related parties	$1.7	$2.7

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

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

	December 31, 2015	December 31, 2014
	millions of Canadian dollars	
Due from related parties:		
Subsidiary of APUC – current[(1)]	$0.7	$—
NSPML – current	1.6	3.5
M&NP – loan receivable – long-term	2.5	2.5
Due to related parties:		
M&NP – current	2.1	1.6
Net due from (to) related parties	$2.7	$ 4.4

(1) Amount due from a subsidiary of APUC is included in accounts receivable.

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

Dividends and Payout Ratios

Emera Incorporated's common share dividends paid in 2015 were Cdn$1.66 (Cdn$0.3875 in Q1, Cdn$0.4000 in Q2 and Q3 and Cdn$0.4750 in Q4) and Cdn$1.48 (Cdn$0.3625 per quarter in Q1, Q2 and Q3 and Cdn$0.3875 in Q4) per common share for 2014, representing a payout ratio of 72.8% of adjusted net income in 2015 and 65.8% for 2014. The increase in the payout ratio is primarily due to an increase in dividends paid greater than growth in adjusted net income.

On August 10, 2015, Emera's Board of Directors approved an increase in the annual common share dividend rate from Cdn$1.60 to Cdn$1.90 per common share.

Enterprise Risk and Risk Management

Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management. Certain risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure such risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The Company's risk management activities are focused on those areas that most significantly impact profitability, quality of income and cash flow. These risks include, but are not limited to, exposure to regulatory and political risk, acquisition, weather, changes in environmental legislation, energy consumption, foreign exchange, capital market and liquidity risk, interest rate, project development and construction risk, cybersecurity, non-regulated plant operational risk, credit, country, commercial relationships, commodity price risk, future employee benefit plan performance and funding, labour, information technology and un-insured risk.

In this section, Emera describes some of the principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, or liquidity or capital resources. The nature of risk is such that no list is comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments in a timely manner. As cost-of-service utilities with an obligation to serve customers, NSPI, Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator of the recovery in adjustments to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. In addition, the commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by significant shifts in government policy and changes in governments. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include: NSPML, M&NP, LIL and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these subsidiaries and their respective regulators determine whether to allow recovery and to adjust rates based upon the subsidiaries' evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

Brunswick Pipeline entered into a 25-year firm service agreement, expiring in 2034, with RECL, which was filed with the NEB. The firm service agreement provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of the Brunswick Pipeline are regulated by the NEB on a complaint basis. EBPC is required to make copies of tariffs and supporting financial information readily available to interested persons.

Persons who cannot resolve traffic, toll and tariff issues with EBPC may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of the Brunswick Pipeline's tolls.

Acquisition Risk

The risks associated with Emera's acquisition strategy include potential difficulties inherent in acquisitions that may adversely affect the results of an acquisition and these include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring power to customers, as a result of unplanned outages. Emera responds to significant weather events related outages according to each subsidiary's respective emergency services restoration plan.

Changes in Environmental Legislation and Regulation

Emera is subject to legislation and regulation by federal, provincial, state, regional and local authorities with regard to environmental matters, primarily related to its utility operations. This includes laws and regulations setting greenhouse gas ("GHG") emissions standards and air emissions standards. Emera is also subject to laws and regulations regarding the generation, storage, transportation, use and disposal of hazardous substances and materials.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera.

New emission reductions requirements for the utilities sector are being established by governments in Canada and the United States. Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance. Stricter environmental laws and regulations and enforcement of such laws and regulations in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

Energy Consumption Risk

Typical of utilities, Emera is affected by demand for energy in the areas in which it operates based upon fluctuations in general economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts. Customers' focus on energy efficiency could also result in changes in energy consumption.

Government policies promoting distributed generation and new technology developments enabling those policies, particularly with rooftop solar, have the potential to impact residential sales and thereby revenues. This could negatively impact operations, net earnings and cash flows. Energy costs and clean energy options have increased demand for products enabling the consumers' ability to self-generate.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. In 2015, approximately 50% of Emera's adjusted net income was derived from subsidiaries with U.S. functional currency. As such, its earnings are subject to fluctuations in the Canadian dollar to U.S. dollar exchange rate. As discussed below, the pending Acquisition will increase this percentage significantly.

The Company identifies and hedges significant transactional currency risks in accordance with its policies and procedures. Emera does not currently hedge the value of its investments in foreign subsidiaries.

Exchange gains and losses on net investments in foreign subsidiaries are included in accumulated other comprehensive income (loss).

The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and capital projects. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

Emera does not enter into hedges for its foreign currency translation exposure on its non-Canadian assets. Any changes in the Canadian exchange rate will affect the equivalent Canadian dollar value of such assets, and the equivalent Canadian dollar value of these assets, revenues and earnings contributions.

Acquisition

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

The proceeds of the first instalment of the Convertible Debenture Offering and the overallotment were converted to U.S. dollars and invested in short-term U.S. dollar investment grade securities. During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the Final Instalment of the Convertible Debenture Offering of the Acquisition of $1.457 billion. These foreign exchange contracts are economic hedges and do not qualify for hedge accounting. Therefore, all mark-to-market gains and losses related to the forwards and related to the U.S. denominated cash proceeds will be recognized in net income for the period. Until the hedge settles and the USD denominated cash is used to acquire TECO Energy, foreign exchange fluctuations could create significant mark-to-market adjustments that may result in volatility in Emera's earnings.

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

Capital Market and Liquidity Risk

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

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

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

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

The Company is subject to interest rate risk relating to certain sources of expected funds to effect the TECO Energy acquisition. Any movement in interest rates could affect the underlying cost of the instrument used to fund the Acquisition. The Company may enter into interest rate hedging contracts to limit its exposure to fluctuations in interest rates.

For Emera's regulated subsidiaries, the cost of debt is generally passed through to ratepayers. While regulatory ROE rates will generally and indirectly follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Project Development and Construction Risk

ENL's planned investment in the development of the Maritime Link Project has risks commensurate with any large construction project. Risks related to such large projects include impact on costs of schedule delays and risk of cost overruns. Emera has deployed a robust project and risk management approach to this project, led by a team with extensive experience in large projects. There are also significant contractual terms in place protecting Emera and ENL from any exposure to cost overruns to either of Nalcor's projects and with specific provisions for Nalcor sharing in cost overruns of the Maritime Link Project.

In February 2015, ENL entered into a contract with Abengoa S.A., a global Spanish energy company, for the transmission line construction on the Maritime Link Project. On November 25, 2015, Abengoa S.A. filed a notice under Spanish law, which provides for pre insolvency protection in Spain, giving ENL up to four months to reach an agreement with creditors to avoid a full insolvency process. ENL is working closely with Abengoa and the performance bond sureties to minimize project impacts. Work on the Project continues.

Cybersecurity Risk

Emera's reliance on information technology to manage its business exposes the Company to potential risks related to cybersecurity attacks and unauthorized access to the Company's, customers', suppliers', counterparties' and employees' sensitive or confidential information, (which may include personally identifiable information and credit information) through hacking, viruses and otherwise (collectively "cybersecurity threats"). The Company uses information technology systems and network infrastructure, which include controls for interconnected systems of generation, distribution, and transmission, some of which is shared with third parties for operating purposes. Through the normal course of business, the Company also collects, processes, and retains sensitive and confidential customer, supplier, counter- party and employee information.

Despite security measures in place, the Company's systems, assets and information could be vulnerable to cybersecurity attacks and other data security breaches that could cause system failures, disrupt operations, adversely affect safety, result in loss of service to customers and release of sensitive or confidential information. Should such cybersecurity threats materialize the Company could suffer costs, losses and damages; all or some of which may not be recoverable through regulatory processes or otherwise.

Emera Energy Trading and Marketing

The majority of Emera's portfolio of electricity and gas marketing and trading contracts, and in particular its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets, in the event of an operational issue or counterparty default. To measure commodity price risk exposure, Emera employs a number of controls and process, including an estimated value-at-risk analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodity, primarily in natural gas and power positions. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments, as well as its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are all used to manage and mitigate this risk.

Emera Energy Electricity Sales and Non-Regulated Fuel for Generation and Purchased Power

Emera Energy's natural gas fired plants in northeastern United States, operating as merchant facilities, are susceptible to the volatility of the New England electricity market and natural gas prices. Market electricity prices are dependent upon a number of factors, including the projected supply and demand of electricity, natural gas prices, the price of other materials used to generate electricity, the cost of complying with applicable environmental and other regulatory requirements and weather conditions. A material change in any one of these factors can materially affect the profitability of the facilities.

Non-Regulated Plant Operational Risk

Emera owns three combined-cycle gas-fired electricity generating facilities in New England (New England Gas Generation Facilities) as well as a gas fired generating facility and biomass fired generating facility in Maritime Canada (Bayside Power and Brooklyn Energy). Power plant operations involve the risk of outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the affected plant unavailable to provide service. Unplanned outages could result in lost revenues, increased capital costs and maintenance expenses, payment of cover costs for any hedges in place, and reduced profitability. Insurance is maintained to mitigate operating risks.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high risk accounts.

Country Risk

Operating revenues outside of Canada constituted 45% (28% from the U.S. and 17% from the Caribbean) of Emera's total operating revenues in 2015 (2014 – 48%, with 31% from the U.S. and 17% from the Caribbean). Emera's investments are currently in regions where the political and economic risk levels are considered by the

Company to be acceptable. Emera's operations in some countries may be subject to the following risks: changes in the rate of economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters or economic conditions and market conditions, and change in financial policy and availability of credit.

Commercial Relationships Risk

The Company is exposed to commercial relationships risk in respect of its reliance on certain key partners, suppliers and customers. The Company manages its commercial relationships risk by monitoring credit risk, as discussed below in Credit Risk, and monitoring of significant developments with its customers, partners and suppliers.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. Fuel contracts may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Future Employee Benefit Plan Performance and Funding Risk

Certain Emera subsidiaries have both defined benefit and defined contribution employee benefit plans that cover their employees and retirees. All defined benefit plans are closed to new entrants. The cost of providing these benefit plans varies depending on the plan provisions, interest rates, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels and contributions to the plans) and expectations around future salary growth, inflation and mortality. Two of the largest drivers of cost are investment performance and interest rates, which are affected by global financial and capital markets. Depending on future interest rates and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could affect Emera's cash flows, financial condition and operations.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 49% of the full-time and term employees within the Emera labour force are represented by local unions.

As at December 31, 2015, approximately 7% of the entire labour force is covered by collective labour agreements that will expire within the next 12 months. Emera seeks to manage this risk through ongoing discussions with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labor disruption.

Information Technology Risk

Emera relies on various information technology systems to manage operations. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems.

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities, and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets, as is customary in the industry. The cost of this coverage is not economically viable. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred by the Company and its subsidiaries will be covered by insurance. Emera's regulated utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates, though there is no assurance the regulatory authority would approve such application in whole or in part.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by Emera and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on Emera's results of operations, cash flows and financial position, if regulatory recovery is not available. A limited portion of Emera's property and casualty insurance is placed with a wholly owned captive insurance company. If a loss is suffered by the captive insurer, it is not able to recover that loss other than through future premiums.

Risk Management Including Financial Instruments

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the Enterprise Risk Management Committee, whose responsibilities include preparing and updating a "Risk Dashboard" for the Board of Directors on a quarterly basis. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange and interest rates through contractual protections with counterparties where practicable, as well as by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively, these contracts and financial instruments are considered "derivatives."

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to accumulated other comprehensive income (loss) and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of the cash flow hedges is recognized in net income in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value, with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. Management believes that any gains or losses resulting from settlement of these derivatives be refunded to or collected from customers in future rates.

Derivatives that do not meet any of the above criteria are designated as held for trading ("HFT") and are recognized on the balance sheet at fair value. All gains or losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

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	**March 31 2016**	**December 31 2015**
	millions of Canadian dollars	
Derivative instrument assets (current and other assets)	$11.7	$19.8
Derivative instrument liabilities (current and long-term liabilities)	(28.5)	(46.2)
Net derivative instrument assets (liabilities)	$(16.8)	$(26.4)

As at	**December 31, 2015**	**December 31, 2014**
	millions of Canadian dollars	
Derivative instrument assets (current and other assets)	$19.8	$23.0
Derivative instrument liabilities (current and long-term liabilities)	(46.2)	(19.2)
Net derivative instrument assets (liabilities)	$(26.4)	$3.8

Hedging Impact Recognized in Net Income

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

	Three months ended March 31		**Year ended December 31**	
	2016	**2015**	**2015**	**2014**
	millions of Canadian dollars			
Operating revenues – regulated	$(3.2)	$(2.1)	$(9.0)	$(3.7)
Non-regulated fuel for generation and purchased power	4.2	5.6	4.8	0.9
Income from equity investments	(0.3)	(0.2)	(0.6)	(0.5)
Interest expense, net	$—	$—	—	(0.2)
Effective net gains (losses)	$ 0.7	$ 3.3	$(4.8)	$(3.5)

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

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

	Three months ended March 31		Year ended December 31	
	2016	2015	2015	2014
	millions of Canadian dollars			
Non-regulated fuel for generation and purchased power	$(1.0)	$(0.6)	$(0.1)	$2.7
Ineffective gains (losses)	$(1.0)	$(0.6)	$(0.1)	$2.7

Regulatory Items Recognized on the Balance Sheets

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

	Three months ended March 31	
	2016	2015
	millions of Canadian dollars	
Derivative instrument assets (current and other assets)	$ 131.3	$ 209.9
Regulatory assets (current and other assets)	51.5	64.3
Derivative instrument liabilities (current and long-term liabilities)	(49.8)	(64.3)
Regulatory liabilities (current and long-term liabilities)	(131.3)	(209.9)
Net asset (liability)	$ 1.7	$ —

	December 31, 2015	December 31, 2014
	millions of Canadian dollars	
Derivative instrument assets (current and other assets)	$ 209.9	$ 97.7
Regulatory assets (current and other assets)	64.3	43.6
Derivative instrument liabilities (current and long-term liabilities)	(64.3)	(40.3)
Regulatory liabilities (current and long-term liabilities)	(209.9)	(97.7)
Net asset (liability)	$ —	$ $3.3

Regulatory Impact Recognized in Net Income

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

	Three months ended March 31		Year ended December 31	
	2016	2015	2015	2014
	millions of Canadian dollars			
Regulated fuel for generation and purchased power[(1)]	$3.0	$(1.1)	$41.2	$17.7
Net gains (losses)	$3.0	$(1.1)	$41.2	$17.7

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

Held-for-trading Items Recognized on the Balance Sheets

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

	Three months ended March 31	Year ended December 31	
	2016	*2015*	*2014*
	millions of Canadian dollars		
Derivative instruments assets (current and other assets)	$ 33.7	$ 95.3	$ 107.8
Derivative instruments liabilities (current and long-term liabilities)	(141.8)	(331.9)	(145.3)
Net derivative instrument assets (liabilities)	$(108.1)	$(236.6)	$ (37.5)

Held-for-trading Items Recognized in Net Income

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

	Three months ended March		Year ended December 31	
	2016	2015	2015	2014
	millions of Canadian dollars			
Non-regulated operating revenues	$221.6	$94.0	$14.4	$270.4
Non-regulated fuel for generation and purchased power	(0.7)	0.2	(3.1)	(5.2)
Other income (expenses), net	—	—	(0.8)	—
Net gains (losses)	$220.9	$94.2	$10.5	$265.2

Other Derivatives Recognized on the Balance Sheets

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

	Three months ended March 2016	December 31, 2015	December 31, 2014
	millions of Canadian dollars		
Derivative instruments assets (current and other assets)	$ 1.1	$92.1	$—
Derivative instruments liabilities (current and long-term liabilities)	(7.0)	(2.9)	—
Net derivative instrument assets (liabilities)	$(5.9)	$89.2	$—

Other Derivatives Recognized in Net Income

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

	Three months ended March 31		Year ended December 31	
	2016	2015	2015	2014
	millions of Canadian dollars			
Other income (expense)	$(94.8)	$—	$92.1	$—
Interest expense, net	$ (0.3)	—	(2.9)	—
Total gains (losses)	$(95.1)	$—	$89.2	$—

Disclosure and Internal Controls

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

The Chief Executive Officer and the Chief Financial Officer have caused to be evaluated under their supervision, with the assistance of Company employees, the effectiveness of the Company's DC&P and ICFR, and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2015.

There have been no changes in Emera or its consolidated subsidiaries' ICFR during the period beginning on January 1, 2015 and ending on December 31, 2015, which have materially affected or are reasonably likely to materially affect ICFR.

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

Critical Accounting Estimates

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

Rate Regulation

The rate-regulated accounting policies of NSPI, Emera Maine, BLPC, Domlec, GBPC, and EBPC may differ from accounting policies for non-rate-regulated companies. NSPI, Emera Maine, BLPC, Domlec, and GBPC's accounting policies are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

Emera has recorded Cdn$699.5 million (2014 – Cdn$602.7 million) of regulatory assets and Cdn$370.6 million (2014 – Cdn$201.9 million) of regulatory liabilities as at December 31, 2015.

Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provision of the plan may also affect current and future pension costs. Benefit costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Emera's accounting policy is to amortize the net actuarial gain or loss, which exceeds 10% of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, which is currently nine years. Emera's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country. The discount rate is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. NSPI rounds its discount rate to the nearest 25 basis points. Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged to become Emera Maine. The pension plans related to the pre-merger companies have remained separate and are disclosed separately below. For benefit cost purposes, NSPI's rate was 4.00% for 2015 (2014 – 5.00%) and Bangor Hydro's rate was 3.91% for 2015 (2014 – 4.83%), MPS' rate was 3.77 for 2015 (2014 – 4.59%) and GBPC's rate for 2015 was 4.75% (2014 – 5.00%).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 5.75% for 2015 (2014 – 6.25%) for NSPI and 7.50% for 2015 and 2014 for Bangor Hydro and MPS, and 6.00% for both 2015 and 2014 for GBPC.

The reported benefit cost for defined benefit and defined contribution plans in 2015, based on management's best estimate assumptions, is Cdn$73.0 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2015 benefit cost of a 25 basis point change (0.25%) in the discount rate and asset return assumptions:

	0.25% Increase		0.25% Decrease	
	2015	2014	2015	2014
	millions of Canadian dollars			
Discount rate assumption	$(5.4)	$(5.4)	$5.4	$5.4
Asset return assumption	$(2.7)	$(2.4)	$2.6	$2.4

Unbilled Revenue

Electric revenues are billed on a systematic basis over a one- or two-month period for NSPI and a one- month period for Emera Maine and GBPC. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. EUS Bahamas and Emera Utility Services include an estimate of work completed under contracts but not yet billed at the end of each month. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As at December 31, 2015, unbilled revenues amount to Cdn$144.2 million (2014 – Cdn$141.1 million) on a base of annual operating revenues of approximately Cdn$2,789.3 million (2014 – Cdn$2,938.6 million).

Property, Plant and Equipment

Property, plant and equipment represents 51.5% of total assets recognized on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated property, plant and equipment are determined based on formal depreciation studies and require the appropriate regulatory approval. NSPI's last depreciation study was completed in 2010 and approved by the UARB on May 11, 2011. BLPC's last depreciation study was completed in 2013 and has been submitted for regulatory review. A response time has not been issued. GBPC's last depreciation study was completed in 2015 and was approved on January 25, 2016. Emera Maine's last depreciation study was completed in 2013 and was applied to transmission rates effective January 1, 2014 and distribution rates effective July 1, 2014.

Depreciation expense was Cdn$295.9 million for the year ended December 31, 2015 (2014 – Cdn$277.5 million).

Goodwill Impairment Assessments

Goodwill represents the excess of the acquisition purchase price for Emera Maine and GBPC over the fair values assigned to individual assets acquired and liabilities assumed. Emera is required to perform an impairment assessment annually, or in the interim if an event occurs that indicates the fair value of Emera Maine or GBPC may be below its carrying value. Emera performs its annual impairment test as at October 1.

Goodwill arose on the acquisitions of GBPC and Emera Maine. At December 31, 2015, this goodwill had a total carrying amount of Cdn$264.1 million (December 31, 2014 – Cdn$221.5 million)

Emera's reporting units will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Determining the fair market value of goodwill is susceptible to changes from period to period as assumptions about future cash flows are required.

Emera reviewed the carrying amount of goodwill and no material goodwill impairments existed for the year ended December 31, 2015 or 2014.

Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of the Company's tax returns.

Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit-adjusted risk free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long- lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization." Any accretion expense not yet approved by the regulator is deferred to a regulatory asset in "Property, plant and equipment" and included in the next depreciation study. Accordingly, changes to the ARO or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

The key assumptions used to determine the ARO are as follows:

Asset	Credit-adjusted risk-free rate		Estimated undiscounted future obligation (millions of Canadian dollars)		Expected settlement date (number of years)	
	2015	2014	2015	2014	2015	2014
Thermal	5.1 – 5.3%	5.2 – 5.3%	$142.8	$142.8	17 – 28	18 – 29
Hydro	5.1 – 5.3%	5.1 – 5.3%	127.6	127.6	16 – 46	17 – 47
Wind	5.1 – 5.2%	5.1 – 5.2%	27.4	27.4	13 – 20	14 – 21
Combustion turbines	5.1 – 5.3%	5.1 – 5.3%	8.3	8.3	1 – 30	2 – 31
Transmission & distribution	4.3 – 5.8%	4.1 – 5.8%	21.5	16.5	1 – 10	1 – 11
Pipeline	3.80%	3.80%	18.1	18.1	19.5	19.5
			$345.7	$340.7		

As at December 31, 2015, the AROs recorded on the balance sheet were Cdn$114.7 million (2014 – Cdn$106.2 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately Cdn$320.2 million, which will be incurred between 2016 and 2061. The majority of these costs will be incurred between 2032 and 2047.

Capitalized Overhead

As required by their respective regulators, NSPI, Emera Maine, GBPC, BLPC and Domlec capitalize overhead costs that are not directly attributable to specific utility assets, but to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by their respective regulator. For the year ended December 31, 2015, Cdn$71.6 million (2014 – Cdn$68.4 million) of overhead costs were capitalized to capital assets. Any change in the methodology for the calculation and allocation of overhead costs could have a material impact on the amounts recognized as expenses versus assets.

Financial Instruments

Emera is required to determine the fair value of all derivatives except those which qualify for the normal purchase, normal sale exception. Fair value is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

Level Determinations and Classifications

Emera uses the Level 1, 2 and 3 classifications in the fair value hierarchy. The fair value measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the fair value. Fair values are determined, directly or indirectly, using inputs that are unobservable for the asset or liability. In limited circumstances, Emera may enter into commodity transactions involving non-standard features where market observable data is not available, or contracts with terms that extend beyond five years.

Changes in Accounting Policies and Practices

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

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

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

Consolidation, ASU 2015-02

In February 2015, the FASB issued ASU 2015-02, Consolidation, which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity ("VIE") characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities are subject to re-evaluation under the revised consolidation model. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Interest—Imputation of Interest, ASU 2015-03

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

ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning December 15, 2015. As at December 31, 2015, debt issuance costs associated with line-of-credit arrangements included in "Other long-term assets" were Cdn$4.0 million (December 31, 2014 – Cdn$4.1 million) on Emera's Consolidated Balance Sheets. In accordance with ASU 2015-15 Interest: Imputation of Interest, the Company continues to present deferred issuance costs related to its revolving credit facilities and related instruments in other long-term assets on its Consolidated Balance Sheets.

Compensation—Retirement Benefits, ASU 2015-04

In April 2015, the FASB issued ASU 2015-04, Compensation—Retirement Benefits, which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Intangibles—Goodwill and Other—Internal-Use Software, ASU 2015-05

In April 2015, the FASB issued ASU 2015-05, Intangibles—Goodwill and Other—Internal-Use Software, which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, the customer would account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer would account for the arrangement as a service contract. The guidance does not change GAAP for a customer's accounting for service contracts. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Technical Corrections and Improvements, ASU 2015-10

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

Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, ASU 2016-05

In March 2016, the FASB issued ASU 2016-05, Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. ASU 2016-05 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and early adoption is permitted. Emera has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Investments—Equity Method and Joint Ventures, ASU 2016-07

In March 2016, the FASB issued ASU 2016-07, Investments—Equity Method and Joint Ventures, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. ASU 2016-07 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016, with early adoption permitted. Emera has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Inventory—Simplifying the Measurement of Inventory, ASU 2015-11

In July 2015, the FASB issued ASU 2015-11, Inventory—Simplifying the Measurement of Inventory. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. ASU 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

The new U.S. GAAP accounting policies that are applicable to, and were adopted by Emera, effective during 2015, are described as follows:

Fair Value Measurement Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), ASU 2015-07

In May 2015, the FASB issued ASU 2015-07 removing the requirement to categorize and disclose, within the fair value hierarchy, all investments for which fair value is measured using the net asset value per share as a practical expedient. Emera has early adopted ASU No. 2015-07 effective December 31, 2015 and 2014. The adoption of this update resulted in disclosure of all investments for which fair value is measured using the net asset value per share methodology being disclosed outside of the fair- value hierarchy. As at December 31, 2015, total investments measured using the net asset value per share were $672.4 million (December 31, 2014 – $635.7 million).

Business Combinations—Simplifying the Accounting for Measurement-Period Adjustments, ASU 2015-16

In September 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-16, Business Combinations—Simplifying the Accounting for Measurement-Period Adjustments. The amendment applies to entities that have reported provisional amounts related to a business combination for which the accounting is incomplete by the end of the reporting period and have an adjustment to provisional amounts previously recognized during a later measurement period. Changes in provisional amounts recorded for acquired assets and liabilities are to be adjusted in the period the adjustment is known, with a corresponding adjustment booked to goodwill. The acquirer is no longer required to revise comparative information from prior years for the effect of changes in provisional amounts. The Company has adopted ASU 2015-16 effective Q3 2015, with no impact on the consolidated financial statements as a result of implementation of this standard.

Income Taxes—Balance Sheet Classification of Deferred Taxes, ASU 2015-17

In November 2015, the FASB issued ASU 2015-17, Income Taxes—Balance Sheet Classification of Deferred Taxes, which simplifies the presentation of deferred income taxes. The amendment requires that deferred tax assets and liabilities be classified as noncurrent on the Consolidated Balance Sheets, regardless of whether the deferred income taxes are expected to be recovered or settled within the next twelve months. ASU-2015-17 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued.

The Company has early adopted ASU 2015-17 effective December 31, 2015, and 2014 balances have been retrospectively restated. This change decreased the current deferred income tax asset and liability by Cdn$49.2 million and Cdn$4.1 million respectively on the Consolidated Balance Sheets as at December 31, 2015 (2014 – Cdn$27.9 million and Cdn$15.7 million respectively). As a result of the change the long-term deferred income tax asset increased by Cdn$15.2 million (2014 – Cdn$24.1 million) and the long-term deferred income tax liability decreased by Cdn$29.9 million (2014 – increased by Cdn$11.9 million) on the Consolidated Balance Sheets as at December 31, 2015.

This change also reclassified a Cdn$11.9 million current deferred income tax regulatory liability (2014 – Cdn$8.0 million) to the long-term deferred income tax regulatory asset on the Consolidated Balance Sheets as at December 31, 2015.

Future Accounting Pronouncements

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification, Topic 606. Accounting Standards Codification 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers: Principal versus Agent Considerations. The amendments are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU 2016-10 Revenue from Contracts with Customers: Identifying Performance Obligations and Licensing. The guidance will be effective beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The Company is continuing to evaluate the impact of adoption of these standards on its consolidated financial statements.

Financial Instruments—Recognition and Measurement of Financial Assets and Financial Liabilities, ASU No. 2016-01

In January 2016, the FASB issued ASU 2016-01, Financial Instruments—Recognition and Measurement of Financial Assets and Financial Liabilities. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. ASU No. 2016-01 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. Emera is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases (Topic 842), ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, Leases. The standard increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for lease terms of more than 12 months. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. ASU 2016-02 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and will be applied using a modified retrospective approach.

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

Summary of Quarterly Results

	For the quarter ended								
	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
	millions of Canadian dollars (except per share amounts)								
Operating revenues	$877.0	$731.6	$642.3	$526.9	$888.5	$782.7	$539.0	$566.6	$1,050.3
Net income attributable to common shareholders	44.3	192.1	35.0	10.0	160.1	151.2	28.2	24.5	202.8
Adjusted net income attributable to common shareholders(1)	120.2	87.1	23.3	48.0	171.6	78.5	49.9	44.2	146.6
Earnings per common share – basic	0.30	1.31	0.24	0.07	1.10	1.05	0.20	0.17	1.43
Earnings per common share – diluted	0.30	1.30	0.24	0.07	1.09	1.02	0.20	0.17	1.40
Adjusted earnings per common share – basic(1)	0.81	0.59	0.16	0.33	1.18	0.54	0.35	0.31	1.03

(1) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures".

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. The first quarter is generally the strongest because a significant portion of the Company's operations are in northeastern North America, where winter is the peak electricity season. As the energy industry is seasonal in nature for companies like Emera, seasonal and other weather patterns, as well as the number and severity of storms, can affect the demand for energy and the cost of service. Quarterly results could be affected by items outlined in the Significant Items section and mark-to-market adjustment

Operating Statistics

Five-Year Summary

	Year ended December 31				
	2015	2014	2013	2012	2011
Electric energy sales (GWh)					
Residential	5,740.5	5,615.7	5,623.6	5,372.2	5,458.9
Commercial	11,153.9	10,989.6	7,156.9	6,174.7	6,562.3
Industrial	2,984.1	2,970.8	3,067.4	2,678.7	3,988.5
Other	373.6	385.3	357.9	371.2	347.0
Total electric energy sales	20,252.1	19,961.4	16,205.8	14,596.8	16,356.7
Sources of energy (GWh)					
Thermal – coal	6,364.0	6609.0	7,098.0	6,223.0	6,848.0
– oil	1,668.4	1,584.5	1,417.5	1,355.1	1,070.8
– natural gas	7,782.3	7,691.7	3,685.9	3,726.0	4,304.7
Biomass	272.3	319.8	167.0	—	—
Hydro	1,040.4	1,129.6	1,002.6	828.0	1,414.5
Wind	259.0	258.0	261.0	256.0	247.0
Purchases	4,142.3	3,693.1	3,528.0	3,210.2	3,518.3
Total generation and purchases	21,528.7	21,285.7	17,160.0	15,598.3	17,403.3
Losses and internal use	1,276.6	1,324.3	954.2	1,001.5	1,046.6
Total electric energy sold	20,252.1	19,961.4	16,205.8	14,596.8	16,356.7
Electric customers					
Residential	747,629	742,110	738,444	702,738	696,970
Commercial	85,480	82,076	83,612	79,613	79,817
Industrial	2,628	2,637	2,711	2,521	2,517
Other	9,432	10,421	10,510	20,230	10,446
Total electric customers	845,169	837,244	835,277	805,102	789,750
Capacity					
Emera-owned generating nameplate capacity(MW)					
Coal fired	1,243.0	1,243.0	1,243.0	1,243.0	1,243.0
Dual fired	350.0	350.0	350.0	350.0	350.0
Gas turbines	1,819.0	1,799.0	1,796.5	746.5	666.0
Biomass	90.0	90.0	90.0	—	—
Hydroelectric	402.0	401.6	401.6	395.0	395.0
Wind turbines	82.0	82.0	82.0	82.0	82.0

	Year ended December 31				
	2015	2014	2013	2012	2011
Diesel	241.2	241.2	244.6	231.5	173.0
Steam	40.0	40.0	40.0	40.0	47.0
Independent power producers	593.0	370.0	308.0	300.0	264.0
	4,860.2	4,616.8	4,555.7	3,388.0	3,220.0
Total number of employees	3,454	3,530	3,558	3,374	3,458
km of transmission lines	7,504	7,215	7,224	6,803	6,800
km of distribution lines	46,162	44,811	44,771	39,590	41,600

Regulated Electric	Customers	Employee count	Peak demand (MW)	Energy sales (GWh)	Total assets (billions)	Rate base (billions)	Income (millions)	Allowable ROE 2015	Allowable ROE 2014
NSPI	506,452	1,727	1,825	10,412	4.6	3.8	129.9	8.75-9.25%	8.75-9.25%
Emera Maine	157,891	412	388	2,020	1.6	0.9	45.1	10.3%	10.6%
BLPC(1)	126,190	330	149	915	0.5	0.4	29.7	10.0%	10.0%
GBPC(1)	19,104	205	61	335	0.4	0.3	17.8	10.0%	10.0%
Domlec(1)	35,525	238	17	95	0.1	0.1	7.4	15.0%	15.0%

(1) These subsidiaries use return on rate base, as opposed to ROE.

Five-Year Financial Summary

	Year ended December 31				
	2015	2014	2013	2012	2011
	millions of Canadian dollars				
Consolidated Statements of Income					
Operating Revenues	$ 2,789.3	$2,938.6	$2,230.2	$2,058.6	$2,064.4
Operating expenses					
Regulated fuel for generation and purchased power	814.5	844.3	868.4	810.5	866.4
Regulated fuel and fixed cost adjustments	41.6	46.6	(40.8)	10.0	(8.5)
Non-regulated fuel for generation and purchased power	335.7	401.1	89.8	44.5	73.9
Non-regulated direct costs	19.5	31.3	52.4	56.6	60.9
Operating, maintenance and general	666.8	560.8	505.0	462.9	453.3
Provincial, state and municipal taxes	63.6	58.2	50.5	49.4	49.2
Depreciation and amortization	339.9	329.0	297.8	278.2	251.7
Income from operations	507.7	667.3	407.1	346.5	317.5
Income from equity investments and Other income (expenses), net	249.7	78.9	63.7	53.8	77.4
Interest expense, net	212.6	179.8	172.2	167.1	159.4
Income before provision for income taxes	544.8	566.4	298.6	233.2	235.5
Income tax expense (recovery)	92.4	113.6	43.3	(12.4)	(23.9)
Net income	452.4	452.8	255.3	245.6	259.4
Non-controlling interest in subsidiaries	24.9	19.9	18.5	13.7	11.7
Net income of Emera Incorporated	427.5	432.9	236.8	231.9	247.7
Preferred stock dividends	30.3	26.2	19.3	11.1	6.6
Net income attributable to common shareholders	397.2	406.7	217.5	220.8	241.1
After-tax mark-to-market gain (loss)	67.2	87.5	(41.9)	(9.7)	(3.0)
Adjusted net income attributable to common shareholders(1)	330.0	319.2	259.4	230.5	244.1
Adjusted EBITDA(1)	1,031.2	946.5	829.5	693.2	649.8
Balance Sheets Information					
Current assets(1)	2,595.6	1,410.8	1,152.3	940.2	993.3

	Year ended December 31				
	2015	2014	2013	2012	2011
	millions of Canadian dollars				
Property, plant and equipment, net of accumulated depreciation	6,188.0	5,610.2	5,327.7	4,491.1	4,294.4
Other assets					
Income taxes receivable	48.7	28.9	27.8	—	—
Deferred income taxes[2]	32.2	57.8	67.8	28.9	33.1
Derivative instruments	167.6	92.0	61.6	23.4	39.6
Pension and post-retirement asset	8.7	5.9	0.5	0.1	0.3
Regulatory assets	605.3	487.7	557.8	376.4	312.2
Net investment in direct financing lease	480.1	484.5	487.2	490.0	492.0
Investments subject to significant influence[3]	1,145.3	1,027.6	739.2	536.6	219.8
Available-for-sale investments	116.0	84.4	74.2	141.8	54.6
Goodwill	264.1	221.5	206.5	193.5	197.7
Intangibles, net of accumulated amortization	191.9	134.3	118.4	114.2	100.7
Due from related parties	2.5	2.5	2.5	151.7	2.8
Other long-term assets	166.3	205.3	53.3	48.5	183.1
Total assets	12,012.3	9,853.4	8,876.8	7,536.4	6,923.6
Current liabilities	2,081.3	1,122.9	1,529.9	951.9	801.7
Long-term liabilities					
Long-term debt	3,750.8	3,660.3	3,363.7	3,257.4	3,273.5
Deferred income taxes[2]	761.7	613.3	547.7	312.1	228.6
Derivative instruments	96.1	77.4	27.0	22.4	38.7
Regulatory liabilities	271.7	158.9	119.5	92.5	107.1
Asset retirement obligations	114.7	106.2	98.6	95.0	99.9
Pension and post-retirement liabilities	303.4	360.7	256.4	506.4	530.8
Other long-term liabilities[3]	298.5	48.3	36.8	20.9	19.6
Equity					
Common stock	2,157.5	2,016.4	1,703.0	1,643.7	1,385.0
Cumulative preferred stock	709.5	709.5	514.0	391.6	146.7
Contributed surplus	28.8	8.8	4.1	2.8	3.3
Accumulated other comprehensive income (loss)	136.5	(347.6)	(430.1)	(775.8)	(671.7)
Retained earnings	1,167.8	1,011.7	817.2	788.1	735.9
Total Emera Incorporated equity	4,200.1	3,398.8	2,608.2	2,050.4	1,599.2
Non-controlling interest in subsidiaries	134.0	306.6	289.0	227.4	224.5
Total equity	4,334.1	3,705.4	2,897.2	2,277.8	1,823.7
Total liabilities and equity	12,012.3	9,853.4	8,876.8	7,536.4	6,923.6
Statements of Cash Flow Information					
Cash provided by operating activities	674.2	762.5	564.2	397.6	399.5
Cash used in investing activities	(123.7)	(710.9)	(921.6)	(919.4)	(660.8)
Cash provided by (used in) financing activities	221.1	58.2	362.1	534.2	331.4
Financial ratios ($ per share)					
Earnings per share	$ 2.72	$ 2.84	$ 1.64	$ 1.77	$ 1.99
Adjusted earnings per share[1]	$ 2.26	$ 2.23	$ 1.96	$ 1.85	$ 2.02

(1) A non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures".

(2) Emera early adopted ASU 2015-17 Income Taxes – Balance Sheet Classification of Deferred Taxes. The December 31, 2014 and 2015 periods have been restated.

(3) As at December 31, 2015 and 2014, the negative investment balance for Bear Swamp has been reclassified to "Other long-term liabilities" on the Consolidated Balance Sheets. The 2014 and 2015 carrying values have been restated.

BUSINESS

General Development of the Business

Emera

Emera seeks to deliver long-term growth to investors. Accordingly, annual dividend growth, earnings per common share growth and total shareholder return are the primary measures of performance. Emera is targeting 8% annual dividend growth through 2019. The following table details Emera's one, three and five-year performance for these metrics, as well as the S&P/TSX Capped Utilities Index annualized total shareholder return for those periods:

	For the Year ended December 31, 2015		
	1 year (%)	**3 year (%)**	**5 year (%)**
Dividend per share compound annual growth rate(1)	12.7	6.9	7.4
Adjusted earnings per share compound annual growth rate(2)	1.3	6.9	5.9
Emera annualized total shareholder return(2)	16.4	12.1	11.1
S&P/TSX Capped Utilities Index annualized total shareholder return(3)	(3.5)	2.3	3.5

(1) The dividend per share compound annual growth rate is based on the dividends paid in the year.

(2) The adjusted earnings per share compound annual growth rates do not include Acquisition-related costs and is a non-U.S. GAAP measure described in "Management's Discussion and Analysis—Non-U.S. GAAP Financial Measures".

(3) Total shareholder return combines share price appreciation and dividends per common share paid during the fiscal year to show the total return to the shareholder expressed as an annualized percentage assuming dividends are reinvested each time they are paid.

(4) The S&P/TSX Capped Sector Indices provide liquid and tradable benchmarks for related derivative products of Canadian economic sectors. Constituents are selected from a stock pool of S&P/TSX Composite Index Stocks, and the relative weight of any single index constituent is capped at 25%. The indices are based upon the Global Industry Classification Standards (GICS®). The S&P/TSX Capped Utilities Index imposes capped weights on the index constituents included in the S&P/TSX Composite that are classified in the GICS® utilities sector.

Energy markets worldwide, in particular across North America, are undergoing foundational changes that have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, environmental concerns (including demand for new, less carbon-intensive and renewable generation), lower-cost natural gas, growing demand for new electric heating solutions, and the requirement for large-scale transmission projects to deliver new energy sources to customers. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving the replacement of higher-carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver that energy to market.

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

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

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

Emera targets achieving 75% to 85% of its Adjusted net income from rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows that fund dividends, reinvestment and which is reflective of the Company's risk tolerance. Emera has an annual dividend growth target of 8% through 2019.

In 2015, approximately 65% of Emera's Adjusted net income was earned by its rate-regulated subsidiaries, which is lower than 2014 (i.e., 67%) and is lower than its strategic target mentioned above. Specifically, the lower percentage of Adjusted net income from non-rate regulated subsidiaries is a result of a substantial increase in Emera Energy's earnings primarily due to strong performance by the New England Gas Generation Facilities, and a strengthening U.S. dollar. It is not the result of a change in Emera's risk tolerance, nor is it from additional capital allocations to non-regulated businesses. Rather, it is the result of strong operating and financial performance of existing non-regulated investments and businesses. Following the closing of the Acquisition, the Company is expected to achieve its Adjusted net income target of 75% to 85%.

Emera has grown its asset base to enable growth and deliver on its strategic objectives. Over the last 10 years, Emera's ability to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. This was demonstrated in the Convertible Debenture Offering completed in connection with the Acquisition. In addition to access to debt and equity capital markets, cash flow from operations will continue to play a role in financing the Company's future growth. Maintaining strong, investment grade credit ratings is an important component of Emera's financing strategy.

Business Strategy

Emera's business strategy consists of the following key components:

Focus on identifying reliable and affordable energy solutions, typically including the replacement of higher carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver energy to that market

- Emera is investing Cdn$2.2 billion to build the Maritime Link and associated projects, which will bring clean hydro energy from Labrador to Nova Scotia, and create opportunities for surplus renewable energy to supply other markets.
- NSPI has invested in wind energy, biomass and hydroelectricity, which has driven substantial increases in the portion of its generation mix derived from renewable sources (reaching 27% in 2015 and on track to meet its 40% target by 2020).
- Numerous other investments and initiatives are underway, from a new utility grade solar facility in Barbados to the MREI transmission proposal, designed to deliver new wind energy in northern Maine to markets in southern New England.

Develop strong partnerships and relationships throughout the regions in which we operate and utilize a collaborative approach to strategic partnerships

- The foundation of Emera's strategy is its collaborative approach to strategic partnerships and its ability to develop strong relationships throughout the regions in which it operates. Prime examples of Emera's success in this areas include:
  - The Maritime Link project, where Emera and its partner Nalcor, along with the Government of Canada and the Provinces of Nova Scotia and Newfoundland and Labrador, have entered into numerous agreements and partnerships to deliver and finance the Maritime Link, the Labrador Island Link and the related Muskrat Falls project.

- Emera's SIA with APUC establishes how Emera and APUC will work together to pursue specific strategic investments of mutual benefit. While Emera recently announced that it has reduced its direct investment in APUC, the SIA remains in place as both companies value the partnership.
- Emera has a number of other partnerships and collaborative agreements across its operating regions, including a joint dispatch project between NSPI and NB Power, a partnership between Emera Maine and Central Maine Power Company to develop the MREI, and the Massachusetts Clean Electricity Partnership, an alliance including Brookfield Renewable Partners, Hydro-Québec, Nalcor, NB Power, SunEdison and TDI New England to promote clean energy investments in New England.

Establish a diverse investment and operations profile

- Emera is a geographically diverse company, operating in Canada, the United States, and the Caribbean.
- Its operations include:
  - vertically integrated electric utilities in Nova Scotia, Barbados, Dominica and Grand Bahama;
  - a transmission and distribution electric utility in Maine;
  - a portfolio of generation facilities, including combined-cycle natural gas and pumped storage hydro in Atlantic Canada and the U.S. northeast;
  - investments in two natural gas pipelines in Atlantic Canada and New England;
  - natural gas marketing and trading;
  - a utility services contractor in Atlantic Canada;
  - a Cdn$2.2 billion project to bring clean hydro energy from Labrador to Nova Scotia; and
  - minority interests in numerous energy projects and companies.

Employ operating and governance models that focus on operational excellence, constructive regulatory approaches, proactive stakeholder engagement and a customer focus through service reliability and rate stability

- Emera's focus on maintaining the highest standards of governance practices is evident in a number of ways including, for example:
  - The Maritime Link project's on time and on budget record, notwithstanding the ambitious and ground-breaking nature of the project, the changing economic climate during the course of the project, and the challenge other similar projects have had with budget and schedule;
  - Emera's consistently high ranking (2nd overall in 2015) in a survey of governance practices among Canada's publicly traded companies, conducted each year by the Globe & Mail's Report on Business; and
  - The establishment of operating boards for the Company's subsidiaries, and the inclusion of local business and community leaders on these boards as well as Emera executives. This practice has helped Emera develop constructive regulatory approaches, proactive stakeholder engagement and maintain a customer focus in its businesses in each of the markets it operates in.

Competitive Strengths

We believe we have the following key competitive strengths to enable us to carry out our business strategy.

Diverse, increasingly regulated profile

- The portion of Emera's adjusted net income generated from rate regulated business has grown from 67% in 2014 to 72% in the 12 months ended March 31, 2016. On a pro forma basis, the Acquisition will bring Emera's regulated earnings to greater than 80%.
- Emera targets achieving 75% to 85% of its adjusted net income from rate-regulated subsidiaries, which contribute strong, predictable income and cash flows, and which is reflective of the Company's risk tolerance.

Supportive and stable regulatory environments

- Through its long history of operating regulated businesses, Emera has gained an appreciation for the importance of constructive, professional regulatory oversight. The Company's experience in jurisdictions such as Nova Scotia and Maine, where it has built robust regulatory teams and practices, was a significant factor in making stable regulatory environments a key criteria in its assessment of growth opportunities, including the Acquisition.

Strong balance sheet, cash flow and liquidity position

- Over the last 10 years, Emera's strong balance sheet, and its ability to raise the capital necessary to fund investments has been a strong enabler of its growth. This was demonstrated in Emera's issue of the Convertible Debentures represented by instalment receipts in connection with the Acquisition.
- In addition to access to debt and equity capital markets, cash flow from operations has grown substantially, from Cdn$419 million for the year ended December 31, 2010 to approximately Cdn$674 million for the year ended December 31, 2015.
- Emera and its subsidiaries maintain strong credit metrics, and Emera has consistently maintained a strong, investment grade credit rating, which is an important component of Emera's financing strategy.

Sizeable capital investment plan to drive growth

- Emera has a Cdn$4.2 billion capital investment plan over the next five years, a significant portion of which is related to the Maritime Link and Labrador Island Link projects.
- This capital plan increases to Cdn$8.3 billion, on a pro forma basis, when TECO Energy's US$4.1 billion in planned capital investments are included.

Disciplined investment criteria

- Emera's focused growth strategy and disciplined investment criteria has served it well. Throughout the period of declining interest rates, its investment hurdle rate has remained unchanged, ensuring that any investment met long term criteria.
- Similarly, Emera's strategic target of earning 75-85% of its adjusted net income from rate-regulated subsidiaries meant that the search for growth opportunities in 2014 and 2015 was focused on rate-regulated businesses.

For further information related to Emera's consolidated revenues for the years ended December 31, 2015, December 31, 2014 and December 31, 2013, see "Management's Discussion and Analysis."

The following discussion summarizes key developments in Emera's business and operations over the last three completed financial years.

Pending Acquisition of TECO Energy

On September 4, 2015, the Company announced a definitive agreement for Emera to acquire TECO Energy. TECO Energy shareholders will receive $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.6 billion USD and which includes the assumption of approximately $4.1 billion USD of debt.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy's holdings include: Tampa Electric, an integrated regulated electric utility which serves nearly 725,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves nearly 365,000 customers across Florida; and NMGC, a regulated gas distribution utility which serves more than 520,000 customers across New Mexico.

Giving effect to the Acquisition as if it closed on March 31, 2016, Emera's total assets would have increased from approximately Cdn$11 billion (US$9 billion) to approximately Cdn$28 billion (US$21 billion) and the percentage of its EBITDA that is regulated EBITDA would have increased from approximately 70% to over 90% (excluding Emera Corporate and Other (except for ENL) and TECO Energy discontinued operations, TECO Energy Corporate and Other). See "Unaudited Pro Forma Consolidated Financial Statements." The Acquisition is expected to increase Emera's consolidated rate base by approximately US$6.5 billion and its total customers by approximately 1.6 million. Following the Acquisition, the regulated utility subsidiaries of Emera will serve approximately 2.5 million customers. Emera has fully committed non-revolving term credit facilities in place from a syndicate of banks in an aggregate amount of $6.5 billion USD to ensure the sufficiency of funding to complete the Acquisition. The Acquisition Credit Facilities are comprised of (i) a $4.3 billion USD debt bridge facility, repayable in full on the first anniversary following its advance, and (ii) a $2.2 billion USD equity bridge facility repayable in full on the first anniversary following its advance. Permanent financing of the Acquisition is expected to be obtained before or after closing, from one or more capital market offerings, including debt and preferred equity, as well as from internally generated sources. A portion of the permanent financing has already been arranged through the sale of $2.185 billion of Convertible Debentures. The Acquisition Credit Facilities are available to address any temporary shortfalls while completing the balance of the permanent financing.

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) the proceeds from the Acquisition Capital Markets Transactions including any series of Notes offered hereunder, (ii) the receipt of payment in full on the Final Instalment Date of the Final Instalment due under the Convertible Debentures, (iii) amounts drawn under the Acquisition Credit Facilities, if any, and (iv) existing cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) and other sources available to the Company.

The closing of the Acquisition is expected to occur in mid-2016. It is subject to certain regulatory and government approvals, including approval by the NMPRC and the satisfaction of closing conditions. Below is a summary of the approvals received to date:

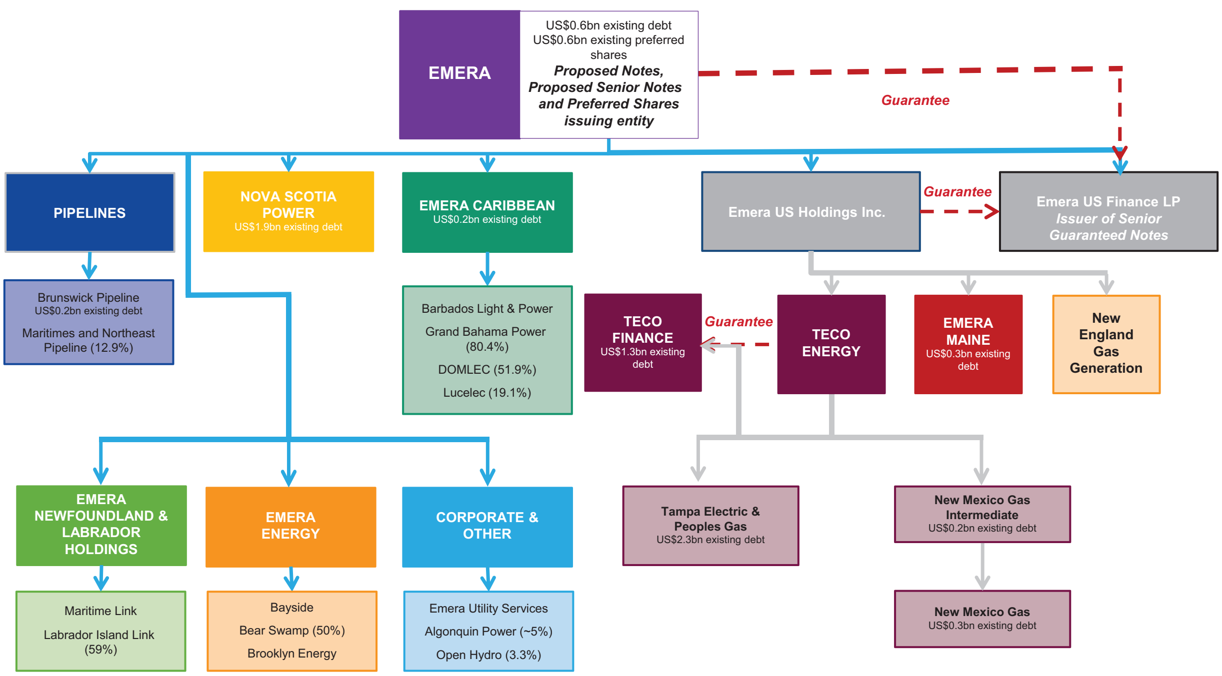
- TECO Energy shareholder approval on December 3, 2015;
- FERC approval on January 20, 2016; and
- Committee on Foreign Investment in the United States approval on March 23, 2016.

Additionally, the waiting period expired on February 5, 2016 under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

On May 2, 2016 the hearing examiner held a hearing in connection with the joint application to the NMPRC of the change in control of NMGC affected by the Acquisition. A final order of the NMPRC is expected in mid-2016.

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

The following chart provides a summary of Emera's organizational structure as of December 31, 2015 on a pro forma basis after giving effect to the Acquisition. The chart depicts (i) Emera's reportable segments (including consolidated and non-consolidated investments) and (ii) selected subsidiaries of Emera



Notes:
[(1)] Organizational chart based on segments outlined in "Management's Discussion and Analysis."

Acquisition Highlights

The Acquisition will propel Emera into a top 20 North American regulated utility as ranked by asset size, with geographic diversity and significant growth potential. TECO Energy represents an accretive opportunity for Emera to further diversify its regulated assets, net income and cash flows in growth markets and constructive regulatory environments, while furthering its strategic objective to supply customers with generation from cleaner sources. Features of the Acquisition and TECO Energy business include:

- **Accretive to Earnings, Growth and Scale**. Management expects the Acquisition to be accretive to Emera's earnings per Common Share and to provide support for Emera's dividend growth target through and beyond 2019 and to improve Emera's long-term growth due to the favourable growth profile of the Florida and New Mexico economies and constructive regulatory environments. As a result of the Acquisition, Emera will become one of the top 20 largest regulated utility companies in North America as ranked by asset size, helping to ensure access to equity and debt capital markets and economies of scale.

- **Acquisition of a Pure-Play Regulated Utility—Increase in Regulated Net Income**. Following the closing of the acquisition of TECO Energy, a utility holding company with virtually all of its net income derived from regulated businesses, the percentage of Emera's net income that is derived from regulated business is expected to increase from approximately 70% to over 80% (excluding Emera Corporate and Other (except for ENL) and TECO Energy discontinued operations, TECO Energy Corporate and Other).
- **Increase in Diversification**. The Acquisition will help Emera diversify net income across several regulatory jurisdictions, geographies and business lines. Emera anticipates that this increased diversification in net income derived from regulated businesses will enhance the stability of net income (partially due to complementary seasonality) and overall quality of cash flows, and should also assist in strengthening its credit profile.
- **Constructive Regulatory Jurisdictions**. The majority of TECO Energy's earnings are derived from Florida, which is a constructive regulatory environment. The FPSC regulates the operations of Tampa Electric and PGS in Florida. In addition, Tampa Electric has a fuel recovery clause and PGS has recovery clauses in place for purchased gas and cast iron and bare steel pipe replacement, as well as higher increased fixed monthly customer charges that reduce volume sensitivity. NMGC, TECO Energy's gas operations located in New Mexico, is regulated by the NMPRC, which allows for the basic costs, excluding purchased gas, storage and interstate capacity, to be provided for through rates.
- **Rate Base Growth Through Capital Investment**. TECO Energy's continued investment in its gas and electric businesses to support customer growth, system reliability and facilities is expected to drive rate base growth over the next several years. Over the long term, Emera believes there is an opportunity to participate in the shift in generation from high carbon sources to low carbon sources as Tampa Electric moves from coal-fired generation to a diversified portfolio of generation that includes gas-fired generating capacity and renewable energy sources.
- **Favourable Florida Economic Indicators**. Florida is the third most populous state in the United States and ranks as the fourth largest economy in the United States. According to the Florida Office of Economic & Demographic Research, job growth and improvements in the housing market are expected to contribute to the growth of Florida's economy and GDP growth is forecast to continue through 2016, with an expected increase of 3.4%.
- **Favourable New Mexico Economic Indicators**. New Mexico is the 36th most populous state in the United States. Sustained job growth of approximately 10,000 jobs per year is forecast through 2017 and the current forecast of GDP growth in 2016 in New Mexico is 2.5% as forecasted by the University of New Mexico Bureau of Business & Economic Research.
- **Experienced Management Team**. TECO Energy's management has a demonstrated track record of working productively with regulators and policy makers, employing a customer focus and regulatory management philosophy in its operating geographies that results in timely recovery of costs and returns on its capital employed. Emera believes that TECO Energy and Emera have complementary management teams and corporate cultures focused on safety and customer service that will facilitate the combination of Emera and TECO Energy following completion of the Acquisition.
- **Community and Stakeholder Engagement**. Emera's approach to combining newly-acquired entities with existing operations is premised on creating value for customers, continuing to invest in the communities in which the acquisition entities operate and aligning Emera's management team and employee base with those of the acquisition entities. Emera intends to continue to invest in local communities in Florida and New Mexico where TECO Energy operates, to preserve TECO Energy's existing headquarter locations and local boards of directors in each state and to retain TECO Energy's existing management team, allowing local managers to be responsive to employees, customers and regulators.

Executive Appointments

On January 15, 2016, Greg Blunden was appointed Chief Financial Officer of Emera, effective March 1, 2016. Mr. Blunden has held financial leadership roles at Emera, Emera Maine and NSPI. Most recently, Mr. Blunden was Vice President, Corporate Strategy & Planning.

On January 15, 2016, Emera's current CFO, Scott Balfour, was appointed Chief Operating Officer, Northeast and Caribbean, effective March 1, 2016. Mr. Balfour will provide senior executive leadership for Emera's existing operations, including NSPI, Emera Energy, Emera Maine, Emera Caribbean, EBPC and Emera Utility Services.

On January 15, 2016, Wayne O'Connor was appointed Vice President, Corporate Strategy & Planning for Emera, effective March 1, 2016. Mr. O'Connor will coordinate Emera's planning and strategy development efforts to grow and expand the Company's business. Previously, he was Executive Vice-President of Operations at NSPI.

On September 22, 2015, Rob Bennett was appointed President and Chief Executive Officer of Emera US Inc., a wholly owned subsidiary of Emera, to lead the integration of TECO Energy. Previously, Mr. Bennett had been the Chief Operating Officer, Eastern Canada.

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

Maritime Link Project and Strategic Partnership with Nalcor Energy on Muskrat Falls Projects

On July 31, 2012, Emera and Nalcor, along with the Provinces of Nova Scotia and Newfoundland and Labrador, executed 13 agreements in respect of the development and transmission of hydroelectric power from Muskrat Falls on the Churchill River in Labrador to the island of Newfoundland, the Province of Nova Scotia and through to New England. The agreements relate to the development of the Muskrat Falls Generating Station, the Labrador Transmission Assets, the Labrador-Island Transmission Link Project and the Maritime Link Project. More specifically, these agreements set out the detailed terms pursuant to which:

- Nalcor will construct and own a 824 MW hydro-electric generating facility at Muskrat Falls on the Lower Churchill River in Labrador and the Labrador Transmission Assets;
- Emera will invest in the Labrador-Island Transmission Link Project; and
- Emera will build, finance and operate for 35 years beginning in 2018, the Maritime Link Project, a transmission project linking the island of Newfoundland to Nova Scotia.

The execution of these agreements was followed, on November 30, 2012, with a finalization of a term sheet detailing the basis upon which the Government of Canada would provide financial support to the Maritime Link Project by way of a loan guarantee. This loan guarantee (the "Federal Loan Guarantee" or "FLG") provides, among other things, that the Government of Canada would fulfill any payment obligations on the guaranteed debt relating to the Maritime Link Project in the event of a default on the guaranteed debt. The FLG enhances the credit rating of the debt financing of the Maritime Link Project to that of the Government of Canada, thus providing a material reduction to the cost of borrowing for the project.

On December 5, 2012, the Newfoundland and Labrador legislature voted in favour of a bill to approve the Muskrat Falls Generating Station, the Labrador Transmission Assets and the Labrador-Island Transmission Link Project.

On December 17, 2012, Emera and Nalcor entered into a sanction agreement enabling both parties to advance their respective projects. Nalcor officially sanctioned the Muskrat Falls Generating Station and the Labrador-Island Transmission Link Project on December 17, 2012, and at that time revised and finalized its capital cost estimates for the Muskrat Falls Generating Station, including Labrador Transmission Assets, from $2.9 billion to $3.6 billion and from $2.1 billion to $2.6 billion for the Labrador-Island Transmission Link Project. This set the stage for construction to begin on the Nalcor projects. On behalf of Emera, ENL's two subsidiaries, NSPML and ENL Island Link Inc. will respectively carry out the development of the Maritime Link Project and invest in the Labrador-Island Transmission Link Project.

On January 28, 2013, NSPML filed an application with the UARB seeking approval of the Maritime Link Project. Previously, on May 17, 2012, the Province of Nova Scotia passed the Maritime Link Act in order to enable a project specific review of the Maritime Link Project by the UARB. Pursuant to the *Maritime Link Act*, the Province of Nova Scotia announced the Maritime Link Approval Process Regulations on October 2, 2012, setting out the approval process to be followed for the Maritime Link Project.

On February 11, 2013, ENL Island Link Inc. invested $67.7 million in the Labrador-Island Transmission Link Project.

On June 21, 2013, NSPML received a release from the Federal Environmental Assessment process, as well as environmental approval from the Provinces of Newfoundland and Labrador and Nova Scotia for the Maritime Link Project.

On July 22, 2013, NSPML received the UARB decision on the Maritime Link Project. The UARB approved the Maritime Link Project subject to certain conditions, including an assurance that additional market-priced energy will be available to Nova Scotians. The UARB approved requested project costs of $1.52 billion and the requested variance amount of $60 million, for total approved project costs of $1.58 billion plus AFUDC.

On October 21, 2013, NSPML filed the Maritime Link Project compliance filing with the UARB. The compliance filing sought confirmation from the UARB that NSPML has complied with each of the UARB conditions, including the condition relating to the availability of market-priced energy.

On November 29, 2013, the UARB approved the Maritime Link Project compliance filing and gave its final approval of the Maritime Link Project. Subsequent to that UARB approval, the Nova Scotia government passed legislative amendments to the Maritime Link Act, which clarified certain aspects of the regulatory framework in respect of the Maritime Link Project and provides NSPML with certain legal rights to facilitate the development and operation of the Maritime Link Project.

In early December 2013, Nalcor Energy and the Government of Newfoundland and Labrador announced the Federal Loan Guarantee associated with the Muskrat Falls Generating Station, the Labrador Transmission Assets and the Labrador-Island Transmission Link Project had been issued, and the financing for the Muskrat Falls Hydroelectric Project had been completed.

On December 13, 2013, NSPML filed its first quarterly compliance filing with the UARB, which included an updated capital cost estimate for the Maritime Link Project of $1.577 billion. Based upon this cost estimate and the application of the terms of the agreement with Nalcor, whereby NSPML will pay 20% of the total cost of the Lower Churchill Project Phase I and Maritime Link Project, the amount of this cost estimate that will be NSPML's responsibility will be $1.5554 billion. The parties have agreed that Nalcor will be responsible for any difference between the $1.5554 billion and the final actual capital costs of the Maritime Link Project, up to $1.577 billion. Any such adjustment will be payable by Nalcor no later than 30 days after the actual capital costs of the Maritime Link Project are finally determined. Any actual capital costs of the Maritime Link Project in excess of the $1.577 billion shall be dealt with in accordance with the provisions of the Maritime Link Joint Development Agreement.

On January 30, 2014, NSPML entered into the first of the Maritime Link Project's three major contracts: the supply and installation of the high-voltage direct current submarine cable. In February 2014, construction activities began in both Nova Scotia and Newfoundland and Labrador, with the initiation of rights-of-way clearing activities.

On March 6, 2014, following satisfaction of the relevant conditions in the FLG term sheet, the Government of Canada issued the Federal Loan Guarantee in respect of the Maritime Link Project.

On April 23, 2014, the MLFT completed its offering of $1.3 billion aggregate principal amount of 3.5% 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 amortization of the bonds is from December 1, 2020 to December 1, 2052. The bonds are guaranteed by the Government of Canada under the FLG. The net proceeds are being used to fund construction of the Maritime Link Project.

Together with certain financing entered into earlier by or on behalf of MLFT and NSPML, this bond offering fully satisfied the obligations of Emera under the FLG Payment Obligation Agreement previously entered into between Emera, NSPML and the Government of Canada. Upon completion of the bond offering, Emera became obligated under the FLG Completion Guarantee previously granted by Emera in favour of the Government Canada. Under the FLG 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 FLG Completion Guarantee.

On June 26, 2014, NSPML entered into the second of the Maritime Link Project's three major contracts: the supply and installation of two HVdc converter stations as well as three substations and two transition compounds.

In Q3 2014, the last of NSPML's labour agreements was signed.

On March 12, 2015, NSPML entered into the third of the Maritime Link Project's three major contracts, with Abengoa S.A., a global Spanish energy and transmission construction company for the construction of approximately 400 km of transmission lines in the Provinces of Newfoundland and Labrador and Nova Scotia. On November 25, 2015, Abengoa S.A. filed a notice under Spanish law, which provides for pre-insolvency protection in Spain, giving Abengoa S.A. the opportunity to reach an agreement with creditors to avoid a full insolvency process. ENL has worked closely with Abengoa S.A. and the performance bond sureties to minimize project impacts. Work on the Maritime Link Project continues.

On April 9, 2015, NSPML and the Assembly of Nova Scotia Mi'kmaq Chiefs signed a Socio-Economic Agreement for the Maritime Link Project. Under the Socio-Economic Agreement, NSPML will support ongoing engagement and commitments made during the environmental assessment process, including Mi'kmaq participation in environmental monitoring and employment and business opportunities for Mi'kmaq people.

Purchase of Natural Gas Generation Facilities in New England

On November 19, 2013, Emera acquired all of the outstanding equity interests in three combined-cycle gas-fired electricity generating facilities in New England that make up EE New England Gas Generation: Bridgeport Energy (520 MW, since upgraded to 560 MW) in Bridgeport, Connecticut; Tiverton Power (265 MW) in Tiverton, Rhode Island; and Rumford Power (265 MW) in Rumford, Maine, for total cash consideration of $573.9 million CAD ($548.4 million USD). This addition of gas generation in the Northeastern United States has been a strategic objective of Emera and is a complement to its hydro investment in the region.

To finance the transaction, Emera utilized $150 million USD received on repayment of a loan to NWP, which was facilitated by the refinancing of that entity's indebtedness; a one-year $350 million USD non-revolving credit facility established by an indirect wholly owned subsidiary of Emera; and other cash resources on hand.

First Wind

On June 15, 2012, Emera and First Wind closed their transaction to jointly own and operate a 419 MW portfolio of wind energy projects in the Northeastern United States through a new company, NWP, owned 51% by First

Wind and 49% by Emera. Emera invested $215 million USD, including transaction costs, and loaned $150 million USD to NWP, to be repaid within five years. On November 14, 2013, Emera received repayment of the $150 million USD loan to NWP in full. First Wind managed and operated the wind energy projects, and Emera Energy Services provided energy management services.

Emera and First Wind also had an agreement relating to additional wind energy projects developed or acquired by First Wind. Under this agreement, on February 11, 2013, Emera, through its interest in NWP, acquired a 49% interest in 34 MW Bull Hill project for $14.4 million USD.

On January 29, 2015, Emera sold its 49% interest in NWP to First Wind for $223.3 million USD.

Strategic Partnership with Algonquin Power & Utilities Corp.

APUC is a diversified generation, transmission and distribution utility traded on the TSX under the symbol "AQN." The distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American-based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate- regulated electric transmission and natural gas pipeline systems in the United States and Canada.

On April 29, 2011, Emera entered into a Strategic Investment Agreement (the "SIA") with APUC. The SIA establishes how Emera and APUC will work together to pursue specific strategic investments of mutual benefit. The SIA outlines "areas of pursuit" for both Emera and APUC. For Emera, these include investment opportunities related to regulated renewable generation and transmission projects within its service territories, and large electric utilities. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. Emera is committed to working with APUC on opportunities that fit within APUC's "areas of pursuit".

The SIA also provides for Emera to acquire up to 25% of APUC through the purchase of common shares issued by APUC to fund certain investment opportunities under the SIA. The acquisition of APUC shares is subject to regulatory approval.

APUC share purchases by Emera have generally been made through the acquisition of subscription receipts in exchange for promissory notes at an agreed upon price, which are then exchangeable into common shares upon meeting certain transaction specific conditions, or at a later date at Emera's option, as applicable. The acquisition and conversion of subscription receipts is subject to approvals required under applicable laws, including the rules of the TSX.

As at March 31, 2016, Emera owned 50.1 million common shares of APUC and had 12.9 million outstanding subscription receipts and dividend equivalents. On May 17, 2016, Emera announced that it had agreed to sell all of its 50.1 million common shares of APUC, representing approximately 19.3% of the issued and outstanding common shares, to a syndicate of underwriters at Cdn$10.85 per common share for an aggregate gross amount of approximately $544 million. The sale was completed on May 24, 2016. Emera intends to use the net proceeds from the sale in support of its general financing requirements, including the Acquisition. Emera continues to hold an equity interest in APUC equivalent to approximately 12.9 million common shares (in the form of subscription receipts and dividend equivalents), which upon conversion represent a continuing common equity interest of approximately 4.75%. The outstanding subscription receipts and dividend equivalents will automatically convert to common shares in Q4 2016, if an election is not made.

As at December 31, 2015, the carrying value of Emera's investment in APUC was $503.7 million (2014 – Cdn$336.4 million).

Gains on Dilution of APUC Equity Investment

In December 2015, APUC closed a 14.355 million common share offering. As a result, Emera recorded a dilution gain of $11.1 million (after-tax earnings of $9.4 million or $0.06 per common share) in "Income from Equity Investments," as described in the MD&A for the year and twelve months ended December 31, 2015.

In Q3 2014 and Q4 2014 respectively, APUC closed 16.86 million and 10.05 million common share offerings. In addition, in Q3 2014, an over-allotment option of 2.52 million common shares was exercised. As a result of these two transactions, in Q3 2014, Emera recorded a gain of $10.8 million (after-tax earnings of $9.1 million or $0.06 per common share) and in Q4 2014, a gain of $7.5 million (after-tax earnings of $6.4 million or $0.04 per common share) in "Income from Equity Investments," as described in the MD&A.

Empire District Electric Company Transaction

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

Nova Scotia Power

Electricity Plan and Rate Stability

On November 9, 2015, the Province of Nova Scotia released its electricity plan to support stable and predictable energy rates until 2019. The electricity plan also provides for the development of performance standards through a 2016 UARB regulatory process. On December 18, 2015, the Province of Nova Scotia enacted the *Electricity Plan Act* (Nova Scotia) (the "Electricity Plan Act"), which requires NSPI to file a three-year rate plan for Fuel Costs in Q1 2016 and to file a three-year GRA to change non-fuel rates by April 30, 2016. NSPI filed its three year rate plan for Fuel Costs on March 7, 2016, indicating an average annual increase of 1.3% per year from 2017 to 2019. NSPI has also confirmed that no GRA for non-fuel cost will be filed for the 2017 to 2019 period.

The Electricity Plan Act directs NSPI to apply non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of certain tax benefits for the South Canoe Wind Project and the Sable Wind Project is to be reserved to be applied to the FAM in the 2017 to 2019 period. The exception to this direction is to apply a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. For more information, see the "Management's Discussion and Analysis—Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals."

Emera Maine

FERC Audit

In November 2014, the FERC commenced an audit covering the 2013 and 2014 period of Bangor Hydro's compliance with conditions established in FERC's orders authorizing its acquisition of MPS, which occurred on January 1, 2014. These two predecessor companies formed Emera Maine. The final audit report was released in early January 2016. The findings in the audit report conclude that Emera Maine did not follow the prescribed methodology for the calculation of AFUDC during the audit period and Emera Maine had included, in rates, costs of the Bangor Hydro and MPS merger prior to making the required filings. Emera Maine will fully comply with the recommendations in the audit report, including making the required filings for the merger costs and re-calculating AFUDC for 2013 and 2014, as ordered, which resulted in an immaterial impact on the Company's consolidated statements of income.

Emera Maine ROE Proceeding

On September 30, 2011 a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end-users filed a complaint with the FERC alleging that the 11.14 per cent base return on equity under the ISO-NE Open Access Transmission Tariff ("OATT") was unjust and unreasonable. On June 19, 2014, the FERC issued an order in connection with this complaint, changing the methodology used to set the ROE for transmission assets.

This change would lower the base transmission ROE to 10.57% for the period of October 1, 2011 to December 31, 2012, subject to a further proceeding to finalize the determination of appropriate rates to be used in such calculation. The FERC decision would also lower the cap on the total ROE (inclusive of incentive adders) for transmission assets to 11.74%. In an order issued on October 16, 2014, the FERC confirmed that the ROE set in its earlier order was appropriate.

On March 3, 2015, in response to requests for rehearing from several parties, FERC affirmed its initial order, setting of the base ROE of 10.57% and capping the total ROE, including the effect of incentive adders, at 11.74%. Notices of Appeal to the U.S. Court of Appeals for the DC Circuit were filed by New England Transmission Operators and the complainants in the case on April 30, 2015. In Q2 2015, Emera Maine began processing the refunds to customers, based on a 10.57% ROE. By court order dated August 20, 2015, the DC Court of Appeals decided to hold the appeal of this case in abeyance pending the outcome of the consolidated cases ("ENE Case" and "MA AG II Case") discussed below.

On December 27, 2012, a second group of consumer advocates, including Environment Northeast filed a complaint with the FERC on similar grounds, arguing that the 11.14% base ROE under the OATT was unjust and unreasonable (the ENE Case). On June 19, 2014, the FERC issued an order in this second ROE case, finding in favour of the complainants and allowing the complaint to proceed. As a result, a new ROE will be calculated and set by the FERC. This complaint created a new 15-month refund period beginning January 1, 2013 through March 31, 2014.

On July 31, 2014, a group of state commissions, state public advocates and end users filed a third complaint with the FERC alleging the ROE earned on transmission investments is unjust and unreasonable and does not reflect current economic conditions (the MA AG II Case). Any potential refund arising from this third complaint will relate to the period from July 31, 2014 to September 30, 2015, and the outcome will set the ROE going forward from the date of decision.

On November 24, 2014, FERC consolidated the ENE Case and MA AG II Case. A subsequent order by the FERC established a schedule for various procedural matters that turned the case over to an Administrative Law Judge in September 2015. Once that judge's recommended decision is rendered, parties may file exceptions, and then the case is set for decision by FERC.

Emera Maine has recorded net reserves of $6.9 million pre-tax (U.S.$5.0 million) (2014 – Cdn$8.5 million) for these refund complaints as at December 31, 2015, based on a 10.57% ROE.

On March 22, 2016, the Administrative Law Judge issued a recommendation to the FERC with respect to the two outstanding ROE complaints (ENE Case and MA AG II Case). Each complaint was for a 15-month period with the recommendation for the ENE Case being 9.59% ROE, with a 10.42% maximum ROE, and the recommendation for MA AG II Case being 10.90% ROE, with a 12.19% maximum ROE.

On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the EMCOS seeking to reduce the base transmission ROE to a maximum of 8.93 per cent and the maximum ROE of 11.24 per cent.

Emera Maine has recorded a reserve of $5.8 million pre-tax (US$4.5 million) (December 31, 2015—$6.9 million or US$5.0 million) for the first two base transmission ROE rate refund complaints. The reserves recorded for these complaints have been recorded as a component of Regulatory Liabilities on the Consolidated Balance Sheets, and the charges to earnings have been a reduction to Operating revenues—regulated on the Consolidated Statements of Income. The reserve was calculated on a 10.57 per cent base and represents Emera Maine's best estimate of the probable outcome. No update has been made to the reserve, as a result of the ALJ recommendation as it is pending approval by the FERC and is considered uncertain until that time. No reserve has been made as a result of the EMCOS complaint, as the outcome is considered uncertain.

U.S. GAAP—Exemptive Relief and Companies Act Relief

On April 28, 2014, Emera was granted exemptive relief by the CSA allowing it to continue to report its financial results in accordance with U.S. GAAP (the "Exemptive Relief"). On July 9, 2014, Emera was granted an order pursuant to the *Companies Act* (Nova Scotia) (the "Companies Act") exempting it from the Companies Act requirement to prepare its annual financial statements in accordance with IFRS (the "Companies Act Relief"). Both the Exemptive Relief and the Companies Act Relief will remain in effect for Emera until the earlier of: (i) January 1, 2019; (ii) the first day of the Company's financial year commencing after the Company ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities. The Exemptive Relief and the Companies Act Relief each replace previous similar exemptive relief that had been granted to Emera in 2012 and 2011 respectively, which would have expired by January 1, 2015.

General Description of the Business—Emera

Emera is an energy and services company with approximately $12 billion in assets. Emera currently provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States, and the Caribbean.

Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions for customers, typically involving the replacement of higher carbon electricity generation with generation from cleaner sources, and the related transmission, distribution infrastructure and delivery of that energy to market.

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

Emera's strategy is based on its collaborative approach to strategic partnerships, its ability to find creative solutions to work within and across multiple jurisdictions, and its experience dealing with complex projects and investment structures. Emera and its subsidiaries had approximately 3,500 employees at December 31, 2015, approximately 49% of whom are unionized.

Emera has grown its business through investments in its rate-regulated subsidiaries that are beneficial to its customers. Emera's regulated subsidiaries include:

- NSPI (see "—NSPI");
- Emera Maine (see "—Emera Maine");
- BLPC, GBPC and Domlec (see "—Emera Caribbean"); and
- EBPC (see "—Pipelines").

Emera has also grown its business through its non-regulated subsidiaries (Emera Energy (see "—Emera Energy") and Emera Utility Services and EUS Bahamas) and additional regulated and non-regulated strategic investments and activities that include:

- Emera's 100% investment in NSPML, a $1.5554 billion transmission project, including two 170-kilometre subsea cables, between the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the ROE component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017;
- Emera's 55.1% investment in the partnership capital of LIL, an electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in NSPML and LIL will equal 49% of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017. Emera's total investment is expected to approximate Cdn$409.1 million;
- Emera's 4.75% (March 31, 2016: 23.2%) investment in APUC. APUC is a diversified generation, transmission and distribution utility traded on the TSX under the symbol "AQN." The distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate-regulated electric transmission and natural gas pipeline systems in the United States and Canada. On May 17, 2016 Emera announced that it had agreed to sell all of the 50.1 million common shares it held in APUC, representing approximately 19.3% of APUC's issued and outstanding common shares, to a syndicate of underwriters at $10.85 per common share for aggregate gross proceeds of approximately Cdn$544 million. The sale was completed on May 24, 2016. Emera continues to hold the subscription receipts and associated dividend equivalents, which represent approximately 4.75% of APUC's issued and outstanding common shares (after giving effect to the conversion of the subscription receipts and associated dividend equivalents); and
- a 12.9% interest in M&NP.

NSPI

NSPI is the primary electricity supplier in Nova Scotia, providing electricity generation, transmission and distribution services in Nova Scotia to approximately 507,000 customers with approximately $4.6 billion in assets and approximately 1,700 employees.

NSPI is a public utility as defined in the Public Utilities Act and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures.

Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time at NSPI's or the UARB's request. NSPI is regulated under a cost of service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's regulated ROE range for 2013 to 2015 was 8.75% to 9.25%, based on an actual average regulated common equity component of up to 40% of actual average regulated capitalization. NSPI's targeted regulated ROE range remains unchanged for 2016.

NSPI operates with a FAM, which enables NSPI to recover fluctuating fuel expenses through annual fuel rate adjustments, which is subject to UARB review and approval. Differences between prudently incurred 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 at March 31, 2016 the FAM had a net liability balance of $46.6 million (December 31, 2015 – Cdn$28.3 million net asset).

Market and Sales

NPSI

Revenue and Electricity Sales by Customer Class

	For the year ended December 31			
	2015	2014	2015	2014
	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
Residential	51.5	50.7	43.1	42.5
Commercial	29.5	29.4	30.1	30.1
Industrial	15.4	16.2	23.6	24.4
Other	3.6	3.7	3.2	3.0
Total	100.0	100.0	100.0	100.0

Energy Sources and Generation

NSPI's energy sources for its electric energy generation are coal, petroleum coke ("petcoke"), natural gas, heavy fuel oil, hydroelectric energy, light fuel oil (gas turbine), biomass and wind. NSPI also purchases electric energy from IPPs in the Province of Nova Scotia and neighbouring markets outside the Province of Nova Scotia.

NSPI owns 2,483 MW of generating capacity, of which approximately 50% is coal-fired; natural gas and/or oil comprise another 28% of capacity; hydro and wind total 19% and biomass-fueled generation of 3%. In addition, NSPI has contracts to purchase renewable energy from IPPs. These IPPs own 496 MW, increasing to 552 MW in 2016 of wind and biomass-fueled generation capacity.

Comparative costs of fuel sources fluctuate from year to year. For information describing the percentage of total electric energy generated by fuel source and for information related to the cost of electricity generation, see the "Management's Discussion and Analysis—NSPI—Regulated Fuel for Generation and Purchased Power".

System Operations

The NSPI Energy Control Center co-ordinates and controls the electric generation and transmission and distribution facilities. The NSPI Energy Control Center is linked to the generating stations and other key facilities through the Supervisory Control and Data Acquisition system, a communication network used by system operators for remote monitoring and control of the power system components.

Through an interconnection agreement with NB Power, NSPI's system has access to other regional power systems and the rest of the interconnected North American electric bulk power systems.

Transmission and Distribution

NSPI transmits and distributes electricity from its generating stations to its customers. NSPI's transmission system consists of approximately 5,000 km of transmission facilities. The distribution system consists of approximately 27,000 km of distribution facilities.

Contribution to Consolidated Net Income

NSPI's contribution to Emera's consolidated net income was $129.9 million in 2015 and $124.9 million in 2014.

Seasonal Nature

Electric sales volume is primarily driven by general economic conditions, population, weather and demand side management. Residential and commercial electricity sales are seasonal in the Province of Nova Scotia, with Q1 typically being the strongest period, reflecting colder weather and fewer daylight hours in the winter season.

Capital Expenditures

NSPI's capital expenditures in 2015 were Cdn$274 million (2014 – Cdn$274 million).

The UARB prescribes and approves depreciation rates and regulated accounting policies. Depreciation rates are reviewed periodically. A settlement agreement on depreciation rates became effective on January 1, 2012. The overall impact of this settlement agreement on the average depreciation rate was immaterial.

Environmental Considerations

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters, primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

Conformance with legislative and NSPI's requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2015.

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix. The most recent target for each year of 2015 through 2019 was 25% of electrical energy which will be derived from renewable sources. That target was exceeded for 2015, with 27% of NSPI's generation mix coming from renewable sources. In 2020, the target is 40% of electrical energy to be derived from renewable sources. The Maritime Link Project will supply 153 MW of firm, on-peak power and approximately 900 GWh per year of renewable electricity to help NSPI meet the legislated target of 40% renewable electricity in 2020. NSPI plans to retire a coal-fired generating unit following the commencement of commercial operations of the Maritime Link.

Emera Maine

On November 29, 2012, Bangor Hydro and MPS submitted a regulatory filing with the MPUC seeking permission to merge into one entity. This proposed change was also subject to regulatory approval by the FERC. The merger application included a proposal to harmonize distribution rates for most residential and small commercial customers on a revenue neutral basis. No change was proposed to other rates or rate classes. Regulatory approval was received in 2013 from the MPUC and FERC for Bangor Hydro and MPS to officially merge on January 1, 2014. Harmonization of rates was deferred to a future case.

Emera Maine's transmission operations are regulated by FERC, and its distribution operations and stranded cost recoveries are regulated by the MPUC. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through the utility's transmission and distribution networks.

Throughout the discussion below, various references are made to the two predecessor entities to Emera Maine, which existed as separate entities until December 31, 2013.

Emera Maine has approximately U.S.$1.1 billion of assets and approximately U.S.$670 million of net rate base. Emera Maine owns and operates approximately 1,700 km of transmission facilities and 15,000 km of distribution facilities and a workforce of approximately 400 people.

Market and Sales

Approximately 55% of Emera Maine's electric revenue represents distribution operations, 31% is associated with local transmission operations and 14% relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

Emera Maine Revenue and Electricity Sales by Customer Class

	For the year ended December 31			
	2015	2014	2015	2014
	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
Residential	47.8	48.3	39.7	39.7
Commercial	36.2	36.5	38.7	38.7
Industrial	8.8	9.1	20.9	20.9
Other	7.2	6.1	0.7	0.7
Total	100.0	100.0	100.0	100.0

Distribution Operations

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. Prior to July 1, 2014, the allowed ROE was 10.2%, on a common equity component of 50%. Effective July 1, 2014, the allowed ROE became 9.55% on a common equity component of 49%.

Transmission Operations

There are two transmission districts for Emera Maine, corresponding to the service territories of the two pre-merger entities.

Bangor Hydro District Transmission

Bangor Hydro District's local transmission rates are regulated by the FERC and set annually on June 1, based upon a formula utilizing prior year actual transmission investments, adjusted for current year forecasted transmission investments. Until October 15, 2014, Bangor Hydro District's allowed ROE for these transmission investments was 11.14%. Effective October 16, 2014, the allowed ROE changed to 10.57%, pending two outstanding complaints filed with the FERC to challenge the ISO-NE OATT allowed base ROE of 11.14%. The common equity component (i.e., the equity base upon which the allowable ROE is earned) is based upon the prior calendar year actual average balances. Effective June 1, 2015, transmission rates for the Bangor Hydro District increased by approximately 21% in connection with its annual transmission formula rate filing (2014 – increased by 13%). The increase is associated primarily with the under- recovery of prior year regional transmission revenues collected in local rates, as well as the recovery of increased transmission plant in service.

Bangor Hydro District's bulk transmission assets are managed by the ISO-NE as part of a region-wide pool of assets. The ISO-NE manages the regions' bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro District, along with all other participating transmission providers, recovers the full cost of service for its transmission assets from the customers of participating transmission providers in New England, based on a regional FERC approved formula that is updated June 1 each year. This formula is based on prior year regionally funded transmission investments, adjusted for current year forecasted investments. Until October 15, 2014, Bangor Hydro District's allowed ROE for these transmission investments ranged from 11.64% to 12.64%. Effective October 16, 2014, the transmission investments allowed ROE changed to a range from 11.07% to 11.74%, pending the two aforementioned complaints filed with FERC. The common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent. On June 1, 2015, Bangor Hydro District's regionally recoverable transmission investments and expenses decreased by 6% (2014 – increased by 7%).

As at December 31, 2015, the Company had accrued U.S.$5.0 million associated with the FERC ROE complaints relating to Bangor Hydro District (2014 – U.S.$7.3 million). Refunds for the first FERC ROE complaint are being made to customers over a one-year period which began with the June 1, 2015 rate change.

MPS District Transmission

MPS District local transmission rates are regulated by the FERC and set annually on June 1 for wholesale and July 1 for retail customers, based on a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted investments. The current allowed ROE for transmission operations is 10.2%. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015, the transmission rates for the MPS District decreased by approximately 24% for wholesale customers (2014 – increased by 2%) and on July 1, 2015 decreased by 22% for retail customers (2014 – increased by 11%) in connection with its annual transmission formula rate filing. These decreases were primarily due to an increase in wholesale transmission revenue that allows for a decrease in local customer transmission rates.

The MPS District electric service territory is not connected to the New England bulk power system and it is not a member of ISO-NE. MPS District is not a party to the previously discussed ROE complaints at the FERC.

Stranded Cost Recoveries

Stranded cost recoveries in Maine are set by the MPUC. Electric utilities are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike transmission and distribution operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, determined under a traditional cost-of-service approach and are fully recoverable. On July 1 of each year, stranded cost rates are adjusted to reflect recovery of cost deferrals for the prior stranded costs rate year under the full recovery mechanism, as well as factor in any new stranded cost information.

Bangor Hydro District Stranded Costs

Bangor Hydro District's net stranded regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract, and deferrals associated with reconciling stranded costs. These net regulatory assets total approximately U.S.$19.7 million as at December 31, 2015 (2014 – U.S.$25.1 million) or 1.8% of Emera Maine's net asset base (2014 – 2.3%).

On July 1, 2014, the Bangor Hydro District stranded cost rates decreased by 10%. Earlier, on March 1, 2014, stranded costs rates had increased by 20%. The allowed ROE used in setting the new rates on July 1, 2014, and March 1, 2014, was 5.9%, with a prescribed common equity component of 48%. The July 1, 2014 rate decrease remained in effect for all of 2015, and there was no rate change on July 1, 2015.

MPS District Stranded Costs

Effective January 1, 2015, the stranded cost rates for the MPS District decreased by approximately 150%. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The allowed ROE used in setting the new rates on January 1, 2015 was 6.75%, with a common equity component of 48%. The reduced stranded cost revenues are offset by reductions in expense and do not affect income. The January 1, 2015 rate decrease remained in effect for all of 2015 and there was no rate change on July 1, 2015. MPS District has a net stranded cost regulatory liability of U.S.$2.68 million as of December 31, 2015.

Contribution to Consolidated Net Income

Emera Maine's contribution to Emera's consolidated net income was U.S.$35.6 million in 2015 and U.S.$38.4 million in 2014.

Seasonal Nature

Electricity sales in Maine vary significantly over the year; Q1 and Q3 are typically the strongest. Q1 reflects colder weather and few daylight hours in the winter season, while Q3 reflects the hotter summer weather and the impact of summer tourism in the state.

Capital Expenditures

Emera Maine's capital expenditures for the year ended 2015 were approximately Cdn$66 million (2014 – Cdn$85 million).

Environmental Considerations

Emera Maine is regulated by the U.S. Environmental Protection Agency for compliance with the Federal Water Pollution Control Act, the Clean Air Act, and other U.S. federal statutes, including those governing the treatment and disposal of hazardous wastes. Emera Maine is also regulated by the State of Maine's Department of Environmental Protection.

Emera Caribbean

As of March 31, 2016, Emera Caribbean includes a 100% indirect interest in BLPC, a 51.9% indirect controlling interest in Domlec, an 80.4% direct and indirect interest in GBPC, a 19.1% indirect interest in Lucelec and a wholly owned indirect interest in Emera Utility Service Bahamas. As of February 25, 2016, Emera Caribbean's indirect interest in BLPC has increased to 100%.

BLPC

BLPC is a vertically-integrated utility and the provider of electricity on the Caribbean island of Barbados with approximately $0.5 billion of assets. It serves approximately 126,000 customers, has a workforce of approximately 330 employees and is regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted to BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. Emera acquired its indirect interest in BLPC through the purchase of approximately 80.1% of the outstanding common shares of LPH, now ECI, and the parent company of BLPC in 2010. In 2015, Emera increased its ownership interest in BLPC to 95.5%. Emera initiated a process to purchase the remaining 4.5% of common shares from minority shareholders of ECI, which was completed on February 25, 2016.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and providing an appropriate return to investors. BLPC's approved allowable regulated return on rate base for 2015 and 2014 is 10%.

A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. The Fair Trading Commission, Barbados has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

Domlec

Domlec is a vertically-integrated utility on the island of Dominica with approximately Cdn$0.1 billion of assets. Domlec serves approximately 36,000 customers, has a workforce of 238 employees, and is regulated by the IRCD. On October 7, 2013, the IRCD issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014 for a period of 25 years. These new licenses replaced the existing license, which was due to expire on December 31, 2015. Domlec's approved allowable regulated return on rate base for 2015 and 2014 was 15%.

A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.

GBPC

Emera, through its wholly owned subsidiary ECHL, has a 50.0% direct and 30.4% indirect interest in GBPC, a vertically- integrated utility and the sole provider of electricity on Grand Bahama Island in The Bahamas with approximately $0.4 billion of assets. GBPC serves approximately 19,000 customers, has a workforce of approximately 205 employees and is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to generate, transmit and distribute electricity on the island until 2054. GBPC's approved allowable regulated return on rate base for 2015 and 2014 was 10%. A fuel pass-through mechanism provides the opportunity to recover fuel costs in a timely manner. ECHL holds its indirect interest in GBPC through ICDU, which in turn owns a 50% interest in GBPC. ICDU is listed on the Bahamas International Securities Exchange.

Effective February 1, 2016, the GBPA approved GBPC's GRA for the 2016 through 2018 period. Residential customers will see decreases of up to 4.5%, while commercial customers will see an increase of 1.5%. Commercial customers consume approximately 70% of GBPC's production. Rates were approved based upon an 8.8% allowable return on rate base. This rate decision will allow for customers to install renewable energy systems and sell their excess energy to GBPC. This is based on a tariff rider scheduled to be in place by Q3 2016.

On June 29, 2012, GBPC announced a new regulatory rate structure which was approved by the GBPA and became effective July 1, 2012. The new regulatory rate structure consists of two components: (i) a base rate intended to recover GBPC's operating expenses, depreciation and return on capital investment; and (ii) a fuel charge intended to recover all of GBPC's fuel costs.

On January 17, 2013, GBPC and the GBPA finalized an Operating Protocol and Regulatory Framework agreement. This agreement formalized the operating protocols and regulatory construct GBPC agreed to in principle in June 2012.

As part of the initial rate case filing under the new regulatory structure, the GBPA approved a return on rate base of 10%. Every three years, commencing in January 2016, base rates will be reviewed and approved by the GBPA.

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% return on rate base to be deferred to a regulatory asset or liability at the rate of 50% of amounts below a 9% return on rate base and 50% of amounts above 11% return on rate base respectively.

Lucelec

Emera indirectly owns a 19.1% interest in Lucelec, a vertically-integrated regulated electric utility on the Caribbean island of St. Lucia. Lucelec is listed on the Eastern Caribbean Securities Exchange.

EUS Bahamas

EUS Bahamas provides utility construction services in The Bahamas.

Market and Sales

Emera Caribbean Revenue and Electricity Sales by Customer Class (1)

	For the year ended December 31			
	2015	2014	2015	2014
	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
Residential	32.4	33.4	33.7	33.4
Commercial	57.0	58.6	56.8	56.9
Industrial	8.8	6.3	7.7	7.7
Other	1.8	1.7	1.8	2.0
Total	100.0	100.0	100.0	100.0

Information included above includes 100% of BLPC, GBPC and Domlec.

Energy Sources and Generation

BLPC's and GBPC's energy sources for their respective electricity generation is primarily heavy fuel oil used for base load generation and light fuel oil used for peaking generation.

BLPC owns approximately 239 MW of generation comprised of: (i) 5 gas turbine units with a combined capacity of 86 MW (light oil and jet fuel oil-fired); (ii) 6 diesel units with a combined capacity of 113 MW (heavy oil-fired); and (ii) 2 steam units with a combined capacity of 40 MW (heavy oil-fired).

GBPC owns approximately 98 MW of heavy fuel oil-fired and medium and slow speed diesel generating units. Domlec owns approximately 20 MW of oil-fired generation and 7 MW of hydro production.

Comparative costs of fuel sources fluctuate from year to year. For information describing the percentage of total electric energy generated by fuel source and for information related to the cost of electricity generation, see the "Management's Discussion and Analysis—Regulated Fuel for Generation and Purchased Power".

System Operation

BLPC, GBPC and Domlec have system control centers which co-ordinate and control the electric generation and transmission facilities with the goal of providing a reliable and secure electricity supply while maintaining economy of operations. The system control centre is linked to the generating stations and other key parts of the system by the "Supervisory Control and Data Acquisition" system, a voice and data communications network.

Transmission and Distribution

BLPC, GBPC and Domlec transmit and distribute electricity from their generating stations to their customers.

BLPC's transmission system consists of 116 km of transmission lines, including major substations connected to the transmission and distribution system. The distribution system consists of 2,800 km of distribution lines which includes distribution supply substations.

GBPC's transmission system consists of 138 km of transmission lines, including major substations connected to the transmission and distribution system. The distribution system consists of approximately 850 km of distribution lines which includes distribution supply substations.

Domlec's transmission system consists of 452 km of transmission lines, including major substations connected to the transmission and distribution system. The distribution system consists of approximately 640 km of distribution lines which includes distribution supply substations.

Contribution to Consolidated Net Income

Emera Caribbean's contribution to Emera's consolidated net income was U.S.$31.4 million in 2015 and U.S.$26.0 million in 2014.

Seasonal Nature

Electricity sales and related generation varies significantly over the year in the Caribbean; Q3 is typically the strongest period, reflecting warmer weather.

Capital Expenditures

Emera Caribbean's capital expenditures for the year ended 2015 were approximately $44 million (2014 – $30 million).

Environmental Considerations

Emera Caribbean has implemented a Health Safety Environmental and Management system to assist in safeguarding the health and safety of its employees, contractors and customers and protection of the environment.

Emera Energy

Emera Energy consists of Emera's wholly owned Emera Energy Services, EE New England Gas Generation, Bayside Power and Brooklyn Energy; and Emera's indirect 50% interest in Bear Swamp. On January 29, 2015, Emera sold its interest in NWP to its 51% partner, First Wind.

Emera Energy Services

Emera Energy Services derives revenue and earnings from the wholesale marketing and trading of natural gas, electricity and other energy-related commodities and derivatives within the Company's strict risk tolerances, including those related to value-at-risk (VaR) and credit exposure. More specifically, Emera Energy purchases and sells physical natural gas and related transportation capacity rights, as well as providing 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, Emera Energy's marketing and trading business currently has approximately 80 employees engaged in commercial activities and related back office, legal and other support functions. The primary market for the marketing and trading business is northeastern North America, including the Marcellus shale gas region, the U.S. Gulf Coast and Central Canada. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. Marketing and trading 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. Emera Energy invests in physical transportation capacity rights to move gas across its portfolio, utilizes financial products to hedge commodity prices, and minimizes open commodity positions in order to maintain the low to moderate risk profile of its marketing and trading business.

Emera Energy Generation

Emera Energy wholly owns and operates a portfolio of high efficiency, non-utility electricity generating facilities in northeast North America. Emera Energy has approximately 125 employees in its wholly owned generation business. The New England facilities participate in the regional capacity market and are compensated for being available to provide power. For the portion of output not committed under power purchase agreements, Emera Energy's generation facilities sell into price-based competitive markets and earn revenues through the physical delivery of power and ancillary services, such as load regulation.

Market and Sales

Information regarding these facilities is summarized in the following table:

Wholly Owned Generation Facilities	Location	Capacity (MW)	Commissioning / In-Service Date	Fuel	Description
New England					
Bridgeport[(1)]	Connecticut	560	1999	Natural gas	Selling electricity and capacity to ISO-NE
Tiverton	Rhode Island	265	2000	Natural gas	Selling electricity and capacity to ISO-NE
Rumford	Maine	265	2000	Natural gas	Selling electricity and capacity to ISO-NE
Total New England		**1,090**			
Maritime Canada					
Bayside Power	New Brunswick	290	2001	Natural gas	Long-term power purchase agreement November – March; Selling electricity to Maritime Provinces and ISO-NE for remainder of year
Brooklyn Energy	Nova Scotia	30	1996	Biomass	Long-term purchase power agreement
Total Maritime Canada		**320**			
Total		**1,410**			

(1) A Q2 2015 upgrade at Bridgeport increased its nameplate capacity from 540 MW to 560 MW.

Information regarding Emera Energy's equity investment in Bear Swamp is summarized below:

Investments in Generation Facilities[(1)]	Ownership (%)	Location	Capacity (MW)	Fuel	Description
New England					
Bear Swamp	50	Massachusetts	600	Hydro	Long-term power purchase agreement and selling electricity and capacity to ISO-NE

(1) In January 29, 2015, Emera completed the sale of its 49% interest in NWP to First Wind for U.S.$223.3 million. Emera's carrying value of its 49% interest as at December 31, 2014 was U.S.$204.4 million.

Information regarding Emera Energy's revenues is summarized below:

Emera Energy Revenue

	For the year ended December 31	
	2015	2014
Electricity sales	$463.1	$517.7
Capacity revenues	43.7	45.8
Marketing and trading margin	83.1	237.4
Total	$589.9	$800.9

Contribution to Consolidated Net Income

Emera Energy's contribution to Emera's consolidated net income was $98.9 million in 2015 and $185.7 million in 2014.

Seasonal Nature

The electricity generation business in the northeast of the United States is seasonal. Q1, Q3 and Q4 are generally the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season, and cooling load in the summer.

Capital Expenditures

Emera Energy's capital expenditures for the year ended 2015 were approximately $42 million (2014 – $63 million). The 2015 capital expenditures included a Q2 2015 upgrade at the Bridgeport facility that increased the nameplate capacity from 540 MW to 560 MW. The 2014 capital expenditures included a major refit and upgrade at the Bridgeport facility that increased the nameplate capacity from 520 MW to 540 MW.

Environmental Considerations

Among other environmental laws and regulations, EE New England Gas Generation is subject to the Regional Greenhouse Gas Initiative (RGGI) for carbon dioxide emissions and the Acid Rain Program for sulphur dioxide emissions. EE New England Gas Generation emits approximately two million tons of carbon dioxide per year. The amount of sulphur dioxide emitted is not considered significant. Changes to these emissions programs could adversely impact financial and operational performance.

Pipelines

Pipelines consists of Emera's wholly owned EBPC and Emera's 12.9% interest in M&NP.

EBPC

EBPC owns Brunswick Pipeline, a 145-km pipeline delivering re-gasified natural gas from the Canaport LNG import terminal near Saint John, New Brunswick to markets in the Northeastern United States. The pipeline travels through southwest New Brunswick and connects with the Maritimes & Northeast Pipeline at the Canada/US border near Baileyville, Maine. Since its commissioning in July 2009, the pipeline has been used solely to transport natural gas for RECL under a 25 year firm service agreement. Brunswick Pipeline is regulated by the NEB, which has classified it as a Group II pipeline.

M&NP

Emera owns a 12.9% interest in the Maritimes & Northeast Pipeline, which is a 1,400 km pipeline that transports natural gas from offshore Nova Scotia to markets in Maritime Provinces and the Northeastern United States.

Contribution to Consolidated Net Income

Emera's wholly owned EBPC and Emera's 12.9% interest in M&NP's contribution to Emera's consolidated net income was $37.5 million in 2015 and $32.7 million in 2014.

Environmental Considerations

Brunswick Pipeline is regulated by the NEB and subject to both federal and provincial environmental laws and regulations. Brunswick Pipeline has comprehensive integrity, safety and environmental programs in place, including an environmental management system and regularly scheduled physical inspections of the pipeline.

Economic Dependence

Brunswick Pipeline has a 25-year firm transport or pay service agreement with RECL, which runs to 2034. The risk of non- payment is mitigated as Repsol, the parent company of RECL, has provided EBPC with a guarantee for all RECL's payment obligations under the firm service agreement.

Emera Corporate and Other

Contribution to Consolidated Net Income

Emera Corporate and Other's contribution to Emera's consolidated net income was $45.3 million in 2015 and $(7.7) million in 2014. Included in the fiscal 2015 results are acquisition-related after-tax costs of $52.8 million and an after-tax mark-to- market gain of $100.5 million related to the effect of U.S. dollar-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the Convertible Debenture Offering for the Acquisition.

Capital Expenditures

Emera Corporate and Other capital expenditures for the year ended 2015 were approximately $10.0 million (2014 – $10.0 million).

Other Emera Environmental Matters

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. Emera estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations will be approximately $29.4 million during fiscal 2016 and are estimated to be $55.9 million from 2017 through 2020. The estimated expenditures do not include: (i) costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions; and (ii) expenditures related to the addition of renewable or cleaner energy generation.

TECO Energy

TECO Energy was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of TEC. TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of TEC and, through its subsidiary, NMGI, owns NMGC. TECO Energy and its subsidiaries had approximately 3,700 employees as of March 31, 2016.

The common stock of TECO Energy trades on the New York Stock Exchange under the symbol "TE".

TECO ENERGY

New Mexico Gas

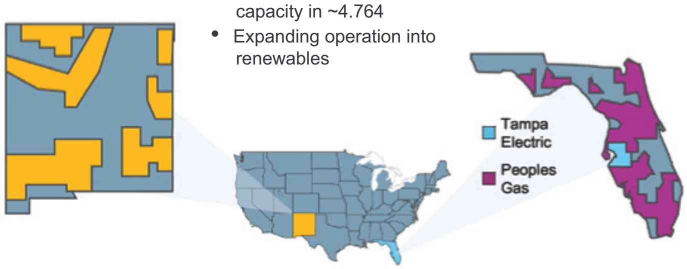
- Regulated gas utility
- Largest gas utility in New Mexico
- Serves almost 520,000 customers
- Expected rate base growth of ~5%
- ~12,000 pipeline miles

Tampa Electric

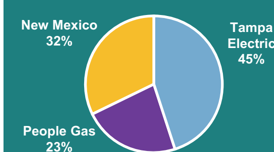
- Regulated gas utility
- Serves 725,000 customers in West Central Florida
- Owns and operates three power plants located in Florida
- Expected rate base growth of more than 10% through 2017, and more than 6% through 2019
- Total generation fleet capacity in ~4.764
- Expanding operation into renewables

Peoples Gas

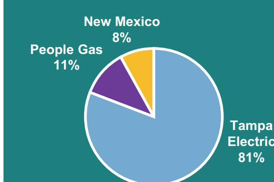
- Regulated gas utility
- Largest gas utility in Florida
- Serves almost 365,000 customers in all major metropolitan areas of the state
- 2014 annual gas throughput of ~1.8bn therms
- ~19,000 pipeline miles



Business Mix



Total customers: ~1,610,000



Total rate base[1] USD$6.5bn

1 Tampa Electric and Peoples Gas average rate base based on earnings surveillance reports filed with FPSC for Dec. 2015. NMGC rate base as of Dec. 31, 2015.

TECO Energy's revenues from continuing operations by regulated subsidiary for the periods presented as follows:

Revenues[(1)] from Continuing Operations

	Three months ended March 31, 2016	Year ended December 31, 2015	Year ended December 31, 2014
		millions of U.S. dollars	
Tampa Electric	$424.5	$2,018.3	$2,021.0
PGS	131.2	407.5	399.6
NMGC	106.6	316.5	137.5
Total regulated businesses	662.3	2,742.3	2,558.1
Other	(2.8)	1.2	8.3
Total revenues from continuing operations	$659.5	$2,743.5	$2,566.4

Net Income (Loss) from Continuing Operations

	Three months ended March 31, 2016	Year ended December 31, 2015	Year ended December 31, 2014
		millions of U.S. dollars	
Tampa Electric	$50.2	$241.0	$224.5
PGS	13.1	35.3	35.8
NMGC	15.2	24.1	10.5
Total regulated businesses	78.5	300.4	270.8
Other[(2)]	(4.8)	(59.2)	(64.4)
Net income from continuing operations	$73.7	$241.2	$206.4

(1) Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.

For further information on the financial condition and results of TECO Energy, reference is made to the audited consolidated financial statements of TECO Energy as at December 31, 2015 and 2014, including the consolidated statements of income, comprehensive income, cash flows and capital for each of the years ended December 31, 2015 and 2014, and the unaudited consolidated financial statements of TECO Energy for the three months ended March 31, 2016, each of which is incorporated by reference in this Prospectus.

Sale of TECO Coal

On September 21, 2015, TECO Diversified, a wholly-owned subsidiary of TECO Energy, entered into a securities purchase agreement for the sale of TECO Coal to Cambrian Coal Corp. The securities purchase agreement did not provide for an up-front purchase payment, but provides for contingent payments of up to U.S.$60 million that may be paid in the years up to 2019 depending on specified coal benchmark prices. TECO Energy retains certain deferred tax assets and personnel related liabilities, but all other TECO Coal assets and liabilities were transferred in the transaction. The retained liabilities included pension liability, which was fully funded at September 30, 2015, and severance agreements, which were paid in 2015. In addition, TECO Energy retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia. TECO Energy is working with the purchaser and the respective permitting agencies to have all permits transferred to the purchaser by the end of 2016.

The securities purchase agreement called for a simultaneous signing and closing, which occurred on September 21, 2015. The closing of this sale essentially completed the process of TECO Energy's exit from unregulated operations to focus on regulated utility businesses.

As a result of the authorization by TECO Energy's Board of Directors authorizing it to enter into negotiations for the sale of TECO Coal, effective in the third quarter of 2014 it was classified as asset held for sale and its results for all periods presented are classified on TECO Energy's financial statements as discontinued operations. TECO Energy recorded a non-cash valuation adjustment of approximately U.S.$76 million, after tax, to the carrying value of TECO Coal to reflect the sales price specified under a sales agreement entered into in October 2014, and an additional U.S.$51 million impairment charge, including a U.S.$7.7 million charge related to black lung liabilities was recorded in 2015.

Tampa Electric

TEC was incorporated in Florida in 1899 and was reincorporated in 1949. TEC is a public utility operating within the State of Florida. Its Tampa Electric division is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties. The principal communities served are Tampa, Temple Terrace, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has two electric generating stations in or near Tampa and one electric generating station in southwestern Polk County, Florida.

Tampa Electric had 2,038 employees as of March 31, 2016, of which 827 were represented by the International Brotherhood of Electrical Workers and 156 were represented by the Office and Professional Employees International Union.

In 2015, Tampa Electric's total operating revenue was derived approximately 52% from residential sales, 30% from commercial sales, 8% from industrial sales and 10% from other sales, including bulk power sales for resale. The sources of operating revenue and MWH sales for the years indicated were as follows:

Operating Revenue

	Three months ended March 31, 2016	Year ended December 31, 2015	2014
	millions of U.S. dollars		
Residential	$217.4	$1,040.3	$1,007.6
Commercial	132.8	608.0	602.0
Industrial – Phosphate	13.1	53.1	59.9
Industrial – Other	25.5	107.1	104.6
Other retail sales of electricity	39.5	177.2	181.9
Deferred and other revenue[1].	(19.4)		
Total retail	408.9	1,985.7	1,956.0
Sales for resale	1.4	3.7	13.0
Other	14.2	28.9	52.0
Total operating revenues	$424.5	$2,018.3	$2,021.0

(1) Primarily reflects the timing of environmental and fuel clause recoveries.

Megawatt-hour Sales

	Three months ended March 31, 2016	Year ended December 31, 2015	2014
	thousands of MWh		
Residential	1,915	9,045	8,656
Commercial	1,388	6,301	6,142
Industrial	461	1,870	1,901
Other retail sales of electricity	401	1,791	1,827
Total retail	4,165	19,007	18,526
Sales for resale	50	115	259
Total energy sold	4,215	19,122	18,785

No significant part of Tampa Electric's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on Tampa Electric. Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric space heating, fewer daylight hours and colder temperatures and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Generation

Tampa Electric has three electric generating stations in service, with a December 2015 net winter generating capability of 4,730 MW. Tampa Electric assets include the Big Bend Power Station (1,632 MW capacity from four coal units and 61 MW from a CT), the Bayside Power Station (1,839 MW capacity from two natural gas combined cycle units and 244 MW from four CTs) and the Polk Power Station (220 MW capacity from the IGCC unit and 732 MW from four CTs). In addition, Tampa Electric installed a 1.6 MW solar array at Tampa International Airport in December 2015.

The Big Bend coal-fired units went into service from 1970 to 1985, and the CT was installed in 2009. The Polk IGCC unit began commercial operation in 1996, and the four CTs began commercial operation from 2000 to 2007. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004 and Units 3 through 6 were completed in 2009. Both the Phillips Power Station and the City of Tampa Partnership Station were retired in November 2015.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,351 Mega Volts Amps. The transmission system consists of approximately 1,302 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,209 pole miles of overhead lines and 5,060 trench miles of underground lines. As of December 31, 2015, there were 747,660 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee simple except that titles to some of the properties are subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements or other property rights for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such ROW for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

TEC has a long-term lease for the office building in downtown Tampa, which serves as headquarters for TECO Energy, Tampa Electric and PGS.

Regulation

Tampa Electric's retail operations are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices and other matters.

In general, the FPSC's pricing objective is to set rates at a level that provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expenses, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes (at a zero cost rate) and an allowed ROE. Base rates are determined in FPSC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other interested parties.

Tampa Electric's results for 2015, 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on September 6, 2013, between Tampa Electric and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On September 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

This agreement provided for the following revenue increases: U.S.$57.5 million effective November 1, 2013, an additional U.S.$7.5 million effective November 1, 2014, an additional U.S.$5.0 million effective November 1, 2015, and an additional U.S.$110.0 million effective January 1, 2017 or the date that an expansion of Tampa Electric's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective no sooner than January 1, 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital, and Tampa Electric also began using a 15-year amortization period for all computer software retroactive to January 1, 2013. Effective November 1, 2013, Tampa Electric ceased accruing U.S.$8.0 million annually to the FPSC-approved self-insured storm damage reserve.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Non-power goods and services transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's retail and wholesale customers, respectively. Given TECO Energy's acquisition of NMGC, Tampa Electric and TECO Energy jointly requested a waiver from FERC in order for Tampa Electric to continue to supply a de-minimis level of non-power goods and services to its affiliates. TECO Energy separately notified FERC that it would no longer qualify to be considered a single-state holding company under the Public Utility Holding Company Act of 2005 as of January 1, 2015, and thus it had formed a centralized service company, TECO Services, Inc., which would provide other non-power goods and services to Tampa Electric and its affiliates. On December 31, 2014, FERC granted Tampa Electric's requested waiver without conditions, effective as of January 1, 2015.

On June 30, 2014, the company filed its required triennial market-power analysis in support of the company's continued ability to effect wholesale market-based rate transactions everywhere, except within Tampa Electric's balancing-authority area. FERC accepted Tampa Electric's triennial filing on November 24, 2015.

Tampa Electric is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters. See "Business—TECO Energy—Environmental Compliance".

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Distributed generation could also be a source of competition in the future, but has not been a significant factor to date. Tampa Electric intends to retain and expand its retail business by managing costs and providing quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including approximately 30 other investor-owned, municipal and other utilities, as well as co-generators and other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a long-term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale markets is affected by the state's Power Plant Siting Act (the "PPSA"), which sets the state's electric energy and environmental policy, and governs the building of new generation involving steam capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses its lower-cost generation to serve its retail customers rather than the wholesale market.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring Investor Owned Utilities ("IOUs"), such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids and provide more stringent standards for the IOUs to recover cost overruns in the event that the self-build option is deemed the most cost-effective.

Fuel

Approximately 52% of Tampa Electric's generation of electricity for 2015 was natural gas-fired, with coal representing approximately 48%. Tampa Electric used its generating units to meet approximately 94% of the total system load requirements, with the remaining 6% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per unit of fuel burned have been as follows:

	2015	2014	2013	2012	2011
	Average cost per MMBTU				
Coal(1)	$ 3.34	$ 3.48	$ 3.36	$ 3.57	$ 3.46
Natural Gas(2)	4.34	5.68	5.23	5.34	6.20
Oil	22.34	0.00	24.72	23.56	21.21
Composite	3.78	4.16	4.00	4.19	4.38
Average cost per ton of coal burned	$79.76	$83.70	$77.79	$84.59	$83.17

(1) Represents the cost of coal and the costs for transportation.

(2) Represents the costs of natural gas, transportation, storage, balancing, hedges for the price of natural gas, and fuel losses for delivery to the energy center.

In 2015, Tampa Electric's generating stations burned fuels as follows: Bayside Power Station burned natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burned a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas; and Polk Power Station burned a blend of low-sulfur coal and petroleum coke (which was gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil.

Coal

Tampa Electric burned approximately 4.0 million tons of coal and petroleum coke during 2015 and estimates that its combined coal and petroleum coke consumption will be about 4.1 million tons in 2016. During 2015, Tampa Electric purchased approximately 67% of its coal under long-term contracts with five suppliers, and approximately 33% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 85% of its coal and petroleum coke requirements in 2016 under long-term contracts with five suppliers and the remaining 15% in the spot market. Tampa Electric has coal transportation agreements with trucking, rail, barge and ocean vessel companies.

Tampa Electric's long-term contracts provide for revisions in the base price to reflect changes in several important cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal.

In 2015, approximately 84% of Tampa Electric's coal supply was deep-mined, approximately 7% was surface-mined and the remaining 9% was petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric cannot predict, however, the effect of any future mining laws and regulations.

Natural Gas

As of December 31, 2015, approximately 63% of Tampa Electric's 1,500,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 78% of its expected gas needs for the April 2016 through October 2016 period. In early March 2016, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2016 gas needs and begin contracting for its 2017 gas needs. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

Oil

Tampa Electric has an agreement in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk Power stations. The agreement has pricing that is based on spot indices.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, govern the placement of Tampa Electric's facilities on the public rights-of-way as it carries for its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. The City of Temple Terrace reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase caused by non-renewal, Tampa Electric would be able to continue to use public rights-of-way within the municipality based on judicial precedent, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates ranging from September 2017 through August 2043.

Franchise fees expense totaled U.S.$46.5 million in 2015. Franchise fees are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the County Commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023.

Capital Expenditures

Tampa Electric's capital expenditures in 2015 of U.S.$595 million, excluding allowance for funds used during construction ("AFUDC") debt and equity, included U.S.$215 million for the Polk 2-5 conversion to combined cycle and related transmission system improvements, U.S.$15 million for solar generation projects at Tampa International Airport and the Big Bend Power Station, U.S.$10 million for the conversion of the Big Bend Station boiler ignition system from distillate oil to natural gas, and approximately U.S.$25 million in the first year of its program to replace its Customer Information System with a state-of-the-art Customer Relationship Management and Billing System ("CRMB"). Tampa Electric also spent approximately US$35 million for hurricane storm hardening for both the transmission and distribution systems, and US$20 million for maintenance capital for environmental control equipment and compliance with environmental regulation. Tampa Electric's 2015 capital expenditures included approximately U.S.$18 million related to environmental compliance and improvement programs, primarily for electrostatic precipitator and scrubber improvements, SCR catalyst replacements and modifications to coal combustion by-product storage areas at the Big Bend Power Station.

As at December 31, 2015, Tampa Electric expected to spend approximately U.S.$575 million on capital expenditure for 2016. For the transmission and distribution systems, Tampa Electric expects to spend U.S.$210 million in 2016, including approximately U.S.$155 million for normal transmission and distribution system expansion and reliability, and approximately U.S.$40 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of U.S.$130 million include approximately U.S.$20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately U.S.$50 million for generating system reliability in 2016 and advance purchases for 2017 unit outages. The capital expenditure forecast includes U.S.$35 million, included in the New Generation category, for a 23 MW solar array that Tampa Electric will build, own and operate at the Big Bend Power Station. Included in 2016 capital expenditure forecast is U.S.$20 million to complete the CRMB project described above.

In the 2017 to 2020 period, Tampa Electric expects to spend approximately U.S.$500 million annually to support normal system growth and reliability, environmental compliance and improvements to facilities to serve customers. This level of ongoing capital expenditures reflects the costs for materials and contractors, long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These programs and requirements include: approximately U.S.$20 million annually for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, average annual expenditures of more than U.S.$90 million to support generating unit availability and reliability; average annual expenditures of almost U.S.$25 million for environmental compliance; average annual expenditures of more than U.S.$35 million for general infrastructure and facilities; average annual expenditures of approximately U.S.$30 million for transmission and distribution system storm hardening; and approximately U.S.$145 million annually for transmission and distribution system capacity improvements to meet expected stronger customer growth and reliability. Included in this period is average annual capital spending of approximately U.S.$25 million to implement the new technology required to modernize the distribution system and install automated metering equipment that is typically associated with "smart grid" technology.

The capital spending forecast for generation includes approximately U.S.$120 million for modifications to the Polk Unit 1 gassifier to produce a high value by-product. Spending on this project and any other revenue enhancing projects must be justified by an internal economic analysis that demonstrates a net benefit.

Tampa Electric's capital spending forecast includes final amounts related to the conversion of the Polk Units 2 - 5 from peaking service to combined cycle with a January 2017 in-service date. Construction commenced in January 2014. The 2016 capital expenditures support the completion of the construction on the power plant and the related transmission system upgrades, start-up testing and precommissioning activities.

New generation and transmission for the 2017 - 2019 period includes approximately U.S.$195 million based on the assumption of a simple cycle peaking unit scheduled to be in-service in early 2020, and continued success in developing additional solar generation projects similar to the 2 MW project at TIA. Tampa Electric recognizes that the proposed Clean Power Plan favors generating resources with lower or no carbon emissions. Tampa Electric may meet the need for additional generating capacity in 2020 with a conventional peaking unit or some combination of conventional generation distributed generation and/or renewable resources such as solar.

Peoples Gas System

PGS operates as the gas division of TEC. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the state of Florida.

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that served approximately 365,000 customers on average for the three months ended March 31, 2016. The system includes approximately 12,100 miles of mains and 6,900 miles of service lines

PGS had 533 employees as of March 31, 2016. A total of 137 employees in five of PGS's 14 operating divisions and call center are represented by various union organizations.

Operating Revenue

In 2015, the total throughput for PGS was approximately 1.8 billion therms. Of this total throughput, 6% was gas purchased and resold to retail customers by PGS, 85% was third-party supplied gas that was delivered for retail transportation-only customers and 9% was gas sold off-system. Industrial and power generation customers consumed approximately 60% of PGS's annual therm volume, commercial customers consumed approximately 27%, off-system sales customers consumed 9% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 35% of total revenues.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. PGS has also seen increased interest and development in natural gas vehicles. There are 42 compressed natural gas filling stations connected to the PGS distribution system.

Revenues and therms for PGS for the periods indicated were as follows:

	Revenues			Therms		
	Three months ended March 31, 2016	Year ended 2015	Year ended 2014	Three months ended March 31, 2016	Year ended 2015	Year ended 2014
	millions of U.S. dollars			*millions of therms*		
Residential	$ 50.5	$137.0	$144.1	32.9	74.9	80.8
Commercial	42.8	138.8	139.1	141.1	470.8	460.5
Industrial	3.3	13.0	13.1	83.5	289.0	274.3
Off system sales	12.9	49.8	39.4	53.9	166.4	84.0
Power generation	2.1	7.2	6.8	190.6	758.3	643.5
Other revenues	16.6	50.5	48.5			
Total	$128.2	$396.3	$391.0	502.0	1,759.4	1,543.1

No significant part of PGS's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on PGS. PGS's business is not highly seasonal, but winter peak throughputs are experienced due to colder temperatures.

Distribution System

PGS's distribution system extends throughout the areas it serves in Florida and consists of approximately 19,000 miles of pipe, including approximately 12,100 miles of mains and 6,900 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS's operations are located in 14 operating divisions throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

Regulation

The operations of PGS are regulated by the FPSC separately from the regulation of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC seeks to set rates at a level that provides an opportunity for a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS's weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed ROE. Base rates are determined in FPSC revenue requirements proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties.

PGS's results reflect base rates established in May 2009, when the FPSC approved a base rate increase of U.S.$19.2 million, which became effective on June 18, 2009 and reflects a return on common equity of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of U.S.$560.8 million.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it delivers to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. In November 2015, the FPSC approved PGS's 2016 PGA cap factor for the period January 2016 through December 2016.

In addition to its base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm charge for energy conservation and pipeline replacement programs. The conservation charge is intended to permit PGS to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are mandated by Florida law and approved and monitored by the FPSC. PGS is also permitted to earn a return, depreciation expenses and applicable taxes associated with the replacement of cast iron/bare steel infrastructure. PGS projects to have all cast iron and bare steel pipe removed from its system within seven years. Lastly, the FPSC requires natural gas utilities to offer transportation-only service to all non-residential customers.

In addition to economic regulation, PGS is subject to the FPSC's safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS's distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, of the Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters. See "—Environmental Compliance."

Competition

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. PGS has a NaturalChoice program, offering unbundled transportation service to all non-residential customers, as well as residential customers consuming in excess of 1,999 therms annually, allowing these customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 23,300 transportation-only customers as of December 31, 2015 out of approximately 37,600 eligible customers.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other facilities and thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation-only services at discounted rates.

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by the Florida Gas Transmission Company through 69 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by a pipeline company through two gate stations located northwest of Jacksonville. Another pipeline company provides delivery through six gate stations. PGS also has one interconnection with its affiliate pipeline company in Clay County, Florida.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by the FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the PGA clause.

PGS procures natural gas supplies using base-load and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices or a fixed price for the contract term.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS's industrial customers are in the categories that are first curtailed in such situations. PGS's tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises and Other Rights

PGS holds franchise and other rights with 116 municipalities and districts throughout Florida. These franchises govern the placement of PGS's facilities on the public rights-of-way as it carries on its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing PGS's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS's property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS's franchise agreements have various expiration dates ranging from the present through 2044. PGS expects to negotiate twelve franchises in 2016. Franchise fees expense totaled U.S.$8.8 million in 2015. Franchise fees are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities and districts are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commission of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates, and these rights are, therefore, considered perpetual.

Capital Expenditures

During the year ended December 31, 2015, PGS capital expenditures were approximately U.S.$95 million, including approximately U.S.$30 million for maintenance of the existing system, U.S.$55 million to expand the system and support customer growth, and U.S.$10 million for replacement of cast iron and bare steel pipe. PGS did not incur any material capital expenditures to meet environmental requirements, nor, as of December 31, 2015, were any anticipated for the 2016 through 2020 period.

As at December 31, 2015, capital expenditures for PGS were expected to be about U.S.$105 million in 2016 and U.S.$430 million during the 2017 to 2020 period. Included in these amounts is an average of approximately U.S.$65 million annually for projects associated with customer growth and system expansion. The PGS capital expenditure forecast includes amounts related to constructing pipelines in the Northeast Florida area to support new Liquefied Natural Gas (LNG) terminals for export and fueling vessels that are dependent on project economics. The remainder represents capital expenditures for ongoing renewal, replacement and system safety, including approximately U.S.$12 million annually for the replacement of cast iron and bare steel pipe, which is recovered through a rider clause approved by the FPSC in 2012.

At PGS, higher capital expenditures are focused on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are more expensive on a cost per MMBTU basis. In the current low oil price environment, the economics of converting to natural gas remain attractive for the long term, and natural gas has lower CO_2 emissions than petroleum based fuels that are attractive to users.

New Mexico Gas Company

On September 2, 2014, TECO Energy completed the acquisition of NMGI contemplated by the acquisition agreement dated May 25, 2013 by and among TECO Energy, NMGI and Continental Energy Systems LLC. As a result of that acquisition, TECO Energy acquired all of the capital stock of NMGI. NMGI, which was incorporated in the state of Delaware in 2008, is the parent company of NMGC. The aggregate purchase price was U.S.$950 million, which included the assumption of U.S.$200 million of senior secured notes of NMGC, plus certain working capital adjustments.

NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in the state of New Mexico. NMGC operates a natural gas distribution system that served approximately 520,000 customers on average for the three months ended March 31, 2016. The system includes approximately 1,600 miles of transmission pipeline, 10,200 miles of mains and 521,400 service lines. NMGC's system interconnects with five interstate pipelines.

Operating Revenue

For 2015, the total throughput for NMGC was over 775 million therms. Of this total throughput, 52% was gas purchased and resold to retail customers by NMGC, 42% was third-party supplied gas that was delivered for retail transportation-only customers and 6% was gas sold or transported off-system. Industrial and power generation customers consumed approximately 26% of NMGC's 2015 annual therm volume, commercial customers consumed approximately 30%, off-system transportation customers consumed 6% and the remaining balance was consumed by residential customers, which represents approximately 38% of total annual therm volume and 72% of NMGC's total annual revenues.

Revenues and therms for NMGC for the three months ended March 31, 2016 and the year ended December 31, 2015 were as follows:

	Revenues		Therms	
	Three months ended March 31, 2016	Year ended December 31, 2015	Three months ended March 31, 2016	Year ended December 31, 2015
	millions of U.S. dollars		*millions of therms*	
Residential	$ 77.7	$229.2	122.6	291.2
Commercial	19.8	59.6	42.0	104.4
Industrial	0.2	1.2	0.4	2.5
Off system sales	0.6	0.3	3.9	1.2
On system transportation	6.6	19.1	95.1	328.7
Off system transportation	0.2	0.9	11.1	47.2
Other revenues	1.5	6.2		
Total	$106.6	$316.5	275.1	775.2

No significant part of NMGC's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on NMGC. NMGC's business is seasonal with much higher volumes and revenues experienced during colder winter months.

Distribution System

NMGC's distribution system extends throughout the areas it serves in New Mexico and consists of approximately 11,800 miles of pipe, including approximately 1,600 miles of transmission pipeline and 10,200 miles of distribution lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

NMGC's operations are located in six operating areas throughout New Mexico. While most of the operations and administrative facilities are owned, a small number are leased.

Regulation

The operations of NMGC are regulated by the NMPRC. The NMPRC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the NMPRC seeks to set rates at a level that provides an opportunity for a utility such as NMGC to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas, gas storage services and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate NMGC's weighted cost of capital, primarily includes its cost for long-term debt and an allowed ROE. Base rates are determined in NMPRC revenue requirements proceedings which occur at irregular intervals at the initiative of NMGC, the NMPRC or other parties.

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately U.S.$34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on January 31, 2012, revising, among other things, base rates for all service provided on or after February 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately U.S.$21.5 million on a normalized annual basis. The monthly residential customer access fee increased from U.S.$9.59 to U.S.$11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition, under the order, NMGC provided $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective October 1, 2014, and will provide $4.0 million of pretax credits to customers in each subsequent 12-month period until new base rates are effective, as reported in Note 21 to the TECO Energy consolidated financial statements included in its 10-K filing for the fiscal year ended December 31, 2015.

NMGC recovers the costs it pays for gas supply and interstate transportation for system supply through the PGAC. This charge is designed to recover the costs incurred by NMGC for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC estimates its cost of gas for the next month (taking into consideration the expected cost of gas to be purchased for the next month, expected demand and any prior month under-recovery or over-recovery of NMGC's cost of gas) and sets the GCBF rate to be used in the next month to recover those estimated costs. For any increase or decrease in cost of gas sold, there is a corresponding increase or decrease in revenue collected through the PGAC. NMGC also has regulatory authority to include a simple interest charge or credit based upon the month-end balance of the PGAC under-recovery or over-recovery of NMGC's cost of gas. NMGC's annual PGAC period runs from September 1 to August 31. The NMPRC requires that NMGC file a reconciliation of the PGAC period costs and recoveries, annually in December. Additionally, NMGC must file a PGAC Continuation Filing with the NMPRC every four years. The purpose of the PGAC Continuation Filing is to establish that the continued use of the PGAC is reasonable and necessary. In January 2013, the NMPRC approved the PGAC Continuation Filing allowing for continued use of the PGAC for another four years. NMGC plans to file its next PGAC Continuation Filing in June 2016 for the four-year period ending December 2020.

In addition to its base rates and PGAC, NMGC's residential customers and customers utilizing NMGC's small and medium volume general services also pay a per-therm charge for energy conservation. The conservation charge is intended to permit NMGC to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are approved and monitored by the NMPRC. The NMPRC requires natural gas utilities to offer transportation-only service to all customer classes.

In addition to economic regulation, NMGC is subject to the NMPRC's safety jurisdiction, pursuant to which the NMPRC regulates the construction, operation and maintenance of NMGC's distribution system. In general, the NMPRC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

NMGC is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters. See "—Environmental Compliance."

Competition

Although NMGC is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. NMGC has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

Pursuant to New Mexico statutes and NMPRC rules and regulations, NMGC is required to provide transportation-only services for all customer classes. NMGC receives its base rates for distribution gas delivery services regardless of whether a customer decides to opt for transportation-only service or continue on NMGC's gas commodity sales service. During the year ended December 31, 2015, NMGC had approximately 4,100 transportation-only end-use customers and approximately 512,000 gas commodity sales service customers. Transportation-only throughput represented 48.5% of total system throughput and 6.3% of total revenue for the year ended December 31, 2015.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other transmission and distribution providers and thereby bypassing NMGC transmission and distribution facilities. In response to this competition, NMGC has developed various programs, including the provision of transportation-only services at discounted rates.

Gas Supplies

NMGC's service territory is situated between two large natural gas production basins (the San Juan Basin to the northwest of NMGC's service territory and the Permian Basin to the southeast of NMGC's service territory). Natural gas is transported from these production basins on major interstate pipelines to NMGC's intrastate transmission system and then to customers using its distribution system. The San Juan Basin typically supplies 85% of NMGC's gas supply, with the Permian Basin supplying most of the remaining balance. NMGC also sources gas from the Piceance Basin in western Colorado and the Green River Basin in Wyoming.

NMGC's transmission and distribution system interconnects with five interstate pipelines owned by various pipeline companies. NMGC has firm pipeline capacity contracts with these pipeline companies. To enhance gas supply and transportation availability, NMGC has an ownership interest in the Blanco Hub, one of the central supply and marketing points in the San Juan Basin. The Blanco Hub interconnects with NMGC's transmission system as well as major nearby gathering systems and interstate pipelines. To provide for system balancing and peak day supply requirements, NMGC contracts for 3.2 billion cubic feet of underground gas storage capacity and gas storage services in an underground facility in west Texas. This storage facility is connected to two major interstate pipelines that, in turn, connect to NMGC's transmission and distribution system.

Gas is purchased from various suppliers at market pools and processing plant tailgates from marketers and producers. NMGC has negotiated standard terms and conditions for the purchase of natural gas under the NAESB and the Gas Industry Standards Board forms of agreement. NMGC purchases gas for resale to its jurisdictional gas sales customers in accordance with an annual gas supply plan filed with the NMPRC.

Gas price spikes, which can occur in high demand winter months, have the potential to significantly increase customer bills. To provide a degree of price protection, NMGC utilizes a hedging plan for a portion of the winter gas supply. The gas hedging activity is discussed in more detail in TECO Energy's Consolidated Financial Statements.

Franchises and Other Rights

Many of NMGC's transmission and distribution facilities are located on lands that require the grant of rights-of-way or franchises from non-tribal governmental entities, Native American tribes and pueblos, or private landowners. In some cases, renewed rights-of-way or franchises must be submitted to the Federal Bureau of Indian Affairs for approval. For the year ended December 31, 2015, NMGC incurred expenditures for rights-of-way or franchise renewals on Native American tribal and pueblo lands that amounted to U.S.$0.3 million.

In 2011, the New Mexico legislature passed legislation confirming the validity and enforceability of agreements with public utilities that provide access to public rights of way, including expired agreements that have continued to be honoured by both the public utility and the local government according to their terms, regardless of the expiration date of the agreements. Accordingly, some of NMGC's expired rights-of-way or franchises remain in effect by statute, though NMGC expects to enter into negotiations to renew expired rights-of-way or franchises upon request. Based on current renewal experience with rights-of-way and franchises on Native American tribal and pueblo lands, NMGC believes that it is likely those rights-of-way or franchises will be renewed at prices that are significantly higher than historical levels. NMGC does not have condemnation rights on Native American tribal and pueblo lands, and, if it is unsuccessful in renewing some or all of these expiring or expired rights-of-way or franchises, it could be obligated to remove its facilities from, or abandon its facilities on, the property covered by the rights-of-way or franchises and seek alternative locations for its transmission or distribution facilities. With respect to land held by non-tribal governmental entities and privately-held land, however, NMGC may have condemnation rights and, thus, in the case where rights-of-way or franchises cannot be renewed by negotiation, NMGC would likely exercise such rights rather than remove or abandon facilities and find alternative locations for such facilities. Historically, rights-of-way and franchise costs have been recovered in rates charged to customers, and NMGC will continue to seek to recover rights-of-way and franchise costs in future rates charged to customers.

Capital Expenditures

During the year ended December 31, 2015, NMGC capital expenditures of U.S.$50 million included amounts to support customer growth, system reliability, facilities and equipment to safely and reliably operate the system, and investments in computer systems and technology required to successfully integrate NMGC financial and related systems with TECO Energy systems. During the year ended December 31, 2015, NMGC did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2016 through 2020 period

As at December 31, 2015, the expected 2016 capital expenditure for NMGC were approximately U.S.$80 million, which included approximately U.S.$30 million annually for ongoing renewal, replacement and system safety and approximately $10 million annually for system expansion to support growth. As at December 31, 2015, the forecast for capital expenditures in 2016 included approximately U.S.$35 million for a transmission pipeline "looping" project to enhance system reliability and capacity for anticipated growth. The forecast beyond 2016 includes approximately U.S.$25 million for software and systems upgrades, which are components of the integration plans with TECO Energy. The NMGC capital spending forecast in 2017 and 2018 include amounts for additional transmission system looping projects to enhance system reliability and capacity. NMGC's capital expenditure forecasts may increase in future years as marketing, economic development and system expansion plans are further developed in the integration process.

Environmental Compliance

TECO Energy's businesses have significant environmental considerations. Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. TEC, through its Tampa Electric and PGS divisions, is a PRP for certain Superfund sites and, through its PGS division, for certain former manufactured gas plant sites. NMGC has not been designated as a PRP and has no former manufactured gas plant sites.

Air Quality Control

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC) and conversion of coal-fired units to natural-gas fired combined cycle; implementation of a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a consent decree and consent final judgment, as settlement of federal and state litigation, to dramatically decrease emissions from its power plants. Tampa Electric has fulfilled the obligations of the consent decree, and the court terminated the consent decree on November 22, 2013. Termination of the consent final judgment was completed on May 6, 2015.

The emission-reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (the "Bayside Power Station"), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Power Station to help reduce SO_2, and installation of SCR systems for NO_x reduction on Big Bend Power Station Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC. Cost recovery for the repowering of the Bayside Power Station was accomplished in Tampa Electric's 2008 rate case.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% from 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system-wide reduction of mercury emissions of more than 90% from 1998 levels.

CAIR/CSAPR

As a result of its completed emission reduction actions, Tampa Electric has achieved the emission-reduction levels called for in Phase I and Phase II of CAIR. In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR on emissions of SO_2 and NO_x. The federal appeals court reinstated CAIR in December 2008 on an interim basis. In July 2011, the EPA issued the final CAIR replacement rule, called the CSAPR. The final CSAPR focused on reducing SO_2 and NO_x in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. Effective January 1, 2015, CSAPR Phase 1 replaced CAIR; Phase 2 of the CSAPR is expected to be implemented in 2017. Compliance with CSAPR, which would be measured at the individual power plant level, would require the addition of scrubbers or SCRs on most coal-fired power plants. In addition, the rule utilized intrastate emissions allowance trading and limited interstate emissions allowance trading to achieve compliance. All of Tampa Electric's conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Power Station Unit 1 IGCC unit removes SO_2 in the gasification process.

On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") granted a motion to stay the implementation of CSAPR in all aspects, which had been scheduled to take effect January 1, 2013, and ordered the reinstatement of CAIR pending the outcome of the litigation. On August 21, 2012, the court vacated CSAPR entirely and remanded it back to the EPA while leaving the CAIR in place. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing the August 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, the EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the EPA's request. Effective January 1, 2015, CSAPR Phase 1 replaced CAIR. Phase 2 of the CSAPR is expected to be implemented in 2017.

SO_2 National Ambient Air Quality Standards ("NAAQS")

On June 2, 2010, the EPA revised the primary SO_2 NAAQS by establishing a new 1-hour standard at a level of 75 parts per billion (ppb). A part of Hillsborough County north of Big Bend Station has a monitor that violates the 2010 SO_2 NAAQS. Although Big Bend Power Station did not contribute to the violation, it has potential effects on the non-attainment area based on air dispersion modeling evaluations and has committed to accept a more stringent SO2 permit limit to ensure the area achieves compliance with the ambient air standards.

The next phase of the SO_2 NAAQS process will address all ambient SO_2 exceedances located outside the designated non-attainment areas. Air dispersion modeling or ambient air monitoring will be used to determine impacts to these areas beginning no earlier than 2018 but no later than 2021. Additional SO_2 emission reductions may be required depending on the outcome of this process.

Hazardous Air Pollutants ("HAPS") Maximum Achievable Control Technology ("MACT") Mercury Air Toxics Standards ("MATS")

The EPA published proposed rules under National Emission Standards for HAPS on May 3, 2011, pursuant to a court order. These rules are expected to reduce mercury, acid gases, organics, and certain non-mercury metals emissions and require MACT. The final Utility MACT rules, now called Mercury Air Toxics Standards ("MATS"), were published in December 2011 with implementation called for in early 2015 with possible extensions to early 2016 or 2017 under certain specific criteria.

On June 29, 2015, the U.S. Supreme Court remanded the EPA's MATS to the D.C. Circuit for failing to properly consider the cost of compliance. In December 2015, the D.C. Circuit ruled that MATS would remain in effect while the EPA performed further cost benefit analysis, and in March 2016 the U.S. Supreme Court denied a request from 20 states to stay MATS pending the D.C. Circuit's review. EPA released a revised cost benefit analysis in April 2016.

All of Tampa Electric's conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit emissions are minimized in the gasification process. Tampa Electric is uniquely positioned to be able to meet the MATS standards without considerable impacts, compared to others who have not taken similar early actions. Therefore, Tampa Electric expects the co-benefits of these control devices for mercury removal to minimize the impact of this rule and expects that it will be in compliance with MATS with nominal additional capital investment.

Carbon Reductions and GHG

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next base load unit, which is scheduled to be in service in January 2017. Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Power Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 30% and 15%, respectively.

Tampa Electric's power plants currently emit approximately 16 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of more than 1.0%, Tampa Electric could emit approximately 16.3 million tons of CO_2 (an increase of approximately 2%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet customer demand.

In 2010, the EPA issued its Final Rule on the mandatory reporting of GHGs, requiring facilities that emit 25,000 metric tons or more of CO2, or its equivalent, per year to begin collecting GHG data under a new reporting system on January 1, 2010, with the first annual report due September 28, 2011. Tampa Electric complied with the initial mandatory reporting requirement, in large part through the methods and procedures already utilized, and continues to submit annual reports as required. The rule also required natural gas distribution, underground coal mining facilities, and electric transmission and distribution companies, including PGS, and Tampa Electric, that emit 25,000 metric tons or more of CO2, or its equivalent, per year to begin collecting GHG data under a new reporting system on January 1, 2011, with the first annual report due September 28, 2012. Tampa Electric and PGS complied with the reporting requirements and continue to submit annual reports as required.

In December 2009, the EPA published the final Endangerment Finding in the U.S. Federal Register. Although the finding was technically made in the context of GHG emissions from new motor vehicles and did not, in itself, impose any requirements on industry or other entities, the EPA claims that the finding triggered GHG regulation of a variety of sources under the Clean Air Act. Related to utility sources, the EPA's "tailoring rule," which addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions, became effective January 2, 2011. A recent U.S. Supreme Court ruling narrowed the EPA's authority to implement this rule but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's ongoing operations, GHG permitting was recently completed for Tampa Electric's next base load unit, the Polk Power Station Unit 2–5 conversion to combined cycle.

In June 2013, President Obama announced his Climate Action Plan, a broad package of mostly administrative initiatives aimed at reducing GHG emissions by approximately 17% below 2005 levels by 2020. As part of the Climate Action Plan, the President directed the EPA to issue a draft rule for existing power plants by June 1, 2014, to finalize the rule by June 1, 2015, and to require states to submit implementation plans by June 30, 2016. In response to this directive, on June 2, 2014, the EPA released a comprehensive proposed rule to limit GHG emissions from existing power plants. The EPA's final rule, the Clean Power Plan, was signed by the Administrator of the EPA on August 3, 2015 and sets emission performance goals that will cut GHG emissions from existing power plants by an average across all states of 32% from their 2005 levels by 2030, with an interim goal for the period from 2022 through 2029. Under the final rule, each state would have to reduce carbon dioxide emissions on a state-wide basis by an amount specified by the EPA adopting either a rate- or mass-based approach; the target amount was determined by the EPA's view of each state's options, including: making power plant efficiency upgrades; shifting from coal-fired to natural gas-fired generation; and investing in zero- and low-emitting power sources, such as renewable and nuclear energy. Under the methodology employed by the EPA , Florida has state-specific rate- and mass-based GHG targets that are in the middle of the range of goals the EPA has set for individual states. Based on the state-specific rate-based goal, generation capacity in Florida has an emission reduction goal equal to a 25% reduction from the 2012 baseline for GHG emission rate of affected electricity generating units. States are intended to have a great deal of flexibility in designing programs to meet their emission reduction targets, including the three approaches noted above or any other measures they choose to adopt, for example, energy efficiency programs. The final rule was published in the U.S. Federal Register on October 23, 2015. Under the rule as published, states had until September 2016 to submit initial plans to achieve their target emission reductions (subject to extension and EPA approval of the states' plans).

On January 21, 2016, the U.S. Court of Appeals for the D.C. Circuit denied requests by 27 states and numerous trade groups for a stay that would have barred the EPA from implementing the carbon regulations for the electricity sector, but indicated that it would expedite the process for considering the lawsuits and would hear oral arguments June 2, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the D.C. Circuit. In a May 16, 2016 order, the D.C. Circuit rescheduled oral argument before the en banc court to September 27, 2016. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018. Prior to the U.S. Supreme Court ruling, Florida had not begun its rulemaking process, and is currently awaiting final resolution of the legal challenges before proceeding with rulemaking. Tampa Electric is evaluating a number of potential compliance scenarios, but until there is consensus in Florida regarding a state plan it will not be possible to develop a final compliance plan. The outcome of this litigation and the rule-making process and its impact on TECO Energy's businesses is uncertain at this time; however, it could result in increased operating costs, and/or decreased operations at Tampa Electric's coal-fired plants. Depending on how the state plan is developed and implemented, the Clean Power Plan could cause an increase in costs or rates charged to customers, which could curtail sales. See "Risk Factors – Risk Factors Relating to the Post-Acquisition Business and Operations of Emera and TECO Energy."

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but it is uncertain if the FPSC would grant such recovery. Prior to the conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Power Station in 2003, nearly all of Tampa Electric's generation was from coal. Upon completion of that conversion, the mix shifted with the increased use of natural gas. Coal is expected to continue to represent an important component in Tampa Electric's fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit 1. Tampa Electric's solid-fuel energy generation was 48% of its total system output in 2015, compared to being approximately 96% of its output in 2001.

Water Supply and Quality

The EPA's final rule under section 316(b) of the Clean Water Act became effective in October 2014. This rule was initially proposed by EPA in response to citizens' lawsuits over perceived impacts to aquatic life resulting from operation of cooling water systems in the U.S. from either impingement (on intake screens) or entrainment (through condensers). Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities as cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms, and Big Bend units 3 and 4 use proprietary fine-mesh screens, BACT, to further reduce impacts to aquatic organisms. Neither station has historically demonstrated any significant adverse environmental impacts. Polk Power Station is not covered by this rule since it does not operate an intake on Waters of the U.S. Tampa Electric has two ongoing projects (one for Bayside and one for Big Bend) to negotiate scheduling with the regulating authority and to complete the biological, technical, and financial study elements necessary to comply with the rule. These study elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend and Bayside Power Stations. The full impact of the new regulations on Tampa Electric will depend on the outcome of subsequent legal proceedings challenging the rule, the results of the study elements performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

EPA determined that numeric water quality standards are required in Florida to implement the Clean Water Act. On January 26, 2010, EPA published proposed "Water Quality Standards for the State of Florida's Lakes and Flowing Waters." There was a long, litigious path in which EPA and FDEP both proposed criteria. Ultimately, the courts upheld the ruling that the Florida regulations meet the requirements of the Clean Water Act. Both Big Bend and Bayside Power Stations already have allocations allotted by the Nitrogen Management Consortium of the Tampa Bay Estuary Program for total nitrogen, which is the limiting nutrient for Tampa Bay. Other criteria related to streams may still directly affect Polk Power Station's cooling reservoir discharge to surface water, and may require the station to reduce the amount of nutrients in the cooling reservoir water before discharge.

After the completion of a study into wastewater discharges by the electric utility industry in 2009, the EPA announced its intent to revise the existing steam electric effluent limit guidelines ("ELGs") that place technology-based limits on wastewater discharges. The final EPA rule was published in the U.S. Federal Register November 3, 2015 and became effective January 4, 2016. The ELGs establish limits for wastewater discharges from flue gas desulfurization ("FGD") processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals ("CCRs"), gasification processes, and flue gas mercury controls. For FGD wastewater, the rule imposed limits for arsenic, mercury, selenium, and nitrate/nitrite which will require the addition of biological treatment at Big Bend Station. Both fly ash and bottom ash transport water have been designated as zero discharge wastewaters, with the exception of use as make-up water in FGD scrubbers. Transport water used as make-up will be subject to FGD wastewater limits at the point of discharge. New limits for gasification processes will likely require additional treatment at Polk Power Station. Cost estimates are being developed based on an evaluation of treatment technologies required to meet the pollutant limits. The new guidelines are expected to be incorporated into NPDES permit renewals to achieve compliance as soon as possible after November 1, 2018, but no later than December 31, 2023.

EPA Waters of the U.S.

In June 2015, the U.S. Army Corps of Engineers and the EPA issued a rule defining "Waters of the United States" ("WOTUS") for purposes of federal Clean Water Act jurisdiction. The final rule took effect on August 28, 2015. The rule has the effect of defining the scope of agency jurisdiction under the Clean Water Act very broadly. In August 2015, a federal judge in North Dakota issued an injunction against the implementation of the rule in certain states. In October 2015, the Sixth Circuit Court of Appeals issued a nationwide stay of WOTUS, effectively ending the implementation of the rule in the 37 states that were not subject to the prior injunction. This stay is temporary, pending determination of the court's jurisdiction over the various challenges to the final rule.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a PRP for certain Superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of March 31, 2016, TEC has estimated its ultimate financial liability to be U.S.$33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the consolidated condensed balance sheets included in TECO Energy's 10-K filing for the fiscal year ended December 31, 2015. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's allocated actual percentage share of the remediation costs.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Coal Combustion Residuals Recycling and Disposal

EPA's final CCR rule became effective on October 19, 2015, and regulates CCRs as non-hazardous solid waste. The rule explicitly allows for encapsulated beneficial uses of CCRs in commercial and industrial products. However, non-encapsulated uses in agricultural and construction applications are allowable only if they meet new environmental criteria.

The rule contains design and operating standards for CCR management units. Tampa Electric is currently evaluating various options for demonstrating compliance with the rule. Potential capital expenditures that are required to achieve compliance with this rule are not expected to be significant. On February 2, 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the ECRC. The CCR rule has been challenged by both utility and environmental groups. Legislation has also been proposed in Congress to amend certain provisions of the CCR rule. Pending the outcome of the litigation and/or legislative amendment, the ultimate impacts of the CCR rule on Tampa Electric are uncertain at this time; however, it could curtail Tampa Electric's ability to market CCRs for beneficial reuse. See "Risk Factors—Risk Factors Relating to the Post-Acquisition Business and Operations of Emera and TECO Energy—Regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs."

Solar Initiatives

In 2015, Tampa Electric announced plans for a 23-MW utility-scale solar photo voltaic project to be installed at Tampa Electric's Big Bend Station. This is the largest solar project in the Tampa Bay area, consisting of more than 70,000 solar panels on 125 acres of land owned by Tampa Electric. Upon completion, it will have the capacity to power more than 3,500 homes. In 2015, Tampa Electric completed the construction of a 2-MW solar photo voltaic energy installation at Tampa International Airport ("TIA"), which is Tampa Electric's first large-scale solar facility. At 2 MW, the solar panels at TIA produce enough electricity to power up to 250 homes. Tampa Electric owns the solar photo voltaic array, and the electricity it produces goes to the grid to benefit all Tampa Electric customers, including the airport. Tampa Electric anticipates developing additional similarly sized small-scale solar photo voltaic installations and we seek opportunities for additional utility-scale installations.

In addition, Tampa Electric has installed 2,135 KW of solar panels to generate electricity from the sun at eight community sites including two schools, Tampa Electric's Manatee Viewing Center, the Museum of Science and Industry, Tampa's Lowry Park Zoo, the Florida Aquarium, and LEGOLAND Florida.

In Florida, a constitutional amendment was proposed that would allow the sale of up to 2 MW of power direct to other customers from rooftop solar panels, potentially bypassing the utility. The Florida Supreme Court ruled that the amendment meets constitutional and statutory requirements to appear on the ballot, however supporters were unable to gather and certify the required number of signatures by the deadline to have it placed on the ballot in 2016. Supporters indicate that they plan to try to have the amendment on the ballot in 2018. Legislation has been proposed for consideration in the 2016 Florida legislative session that essentially mirrors the intent of the constitutional amendment.

A second Florida constitutional amendment regarding solar power generation is proposed for the 2016 ballot that would establish a right for consumers to own or lease solar equipment installed on their property to generate electricity for their own use. State and local governments would retain the ability to protect consumer rights and public health and safety and ensure that consumers that do not choose to install solar are not required to subsidize the costs of backup power and electric grid access for those that do. The Florida Supreme Court ruled that the amendment meets constitutional and statutory requirements to appear on the ballot. Backers of the proposed amendment have gathered and certified the required number of signatures to have it on the 2016 ballot.

Distributed Generation

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small-scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. To date, there has not been a significant amount of distributed generation added to utility systems in Florida. Florida does not have a renewable portfolio standard, and Florida legislation and regulation have minimized social programs and costs in utility rates. However, proposed action by the Florida legislature in 2016 and a potential amendment to the Florida constitution that supporters are seeking to have placed on the ballot in 2018 would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and allow limited sales of electricity by non-utility generators.

Additionally, the EPA's Clean Power Plan rule, if enacted consistent with the rule published in August 2015, could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets. Depending on how the rule is implemented, it could have the effect of increasing TECO Energy's costs or the rates charged to TECO Energy's customers, which could curtail sales.

Increased usage of distributed generation, particularly in those states where solar or wind resources are the most abundant, is reducing utility electricity sales, but not reducing the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Due to the intermittent availability of renewable resources, utilities must invest in adequate generating resources to meet customer demand at the times that renewable resources are not available. Energy storage technologies, such as batteries, are not yet commercially available to fill this demand. Continued utility investment not supported by increased future energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

Conservation

Energy conservation is becoming more important in the GHG emissions reduction debate. Tampa Electric supports the FPSC and its efforts to encourage energy efficiency. In 2015, Tampa Electric continued to offer its customers a comprehensive array of residential and commercial programs that enabled the company to meet its required Demand Side Management (DSM) goals, reduce weather-sensitive peak demand and conserve energy. This strategy continues to allow Tampa Electric to delay construction of future generation facilities. Since their inception, the company's conservation programs have reduced the summer peak demand by 348 MW and the winter peak demand by 740 MW.

In November 2014, the FPSC established new DSM goals for the 10-year period from 2015 to 2024 for all Florida investor-owned electric utilities. In November 2015, Tampa Electric transitioned into the new 2015-2024 DSM plan by discontinuing nine existing DSM programs; creating one new DSM program; modifying twenty-eight existing DSM programs; and retiring the renewable energy systems initiative. This transition supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the Florida Energy Efficiency & Conservation Act. For Tampa Electric, the summer and winter demand goals are 56.9 and 87.4 MWs, respectively, and the energy goal is 144.3 gigawatt-hours over the 10-year period. Establishing these DSM goals for the 10-year period is required every five years. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill. In addition, PGS offers conservation programs that enable customers to reduce their energy consumption, with those costs recovered through a clause on the customer's gas bill.

Legal Proceedings

Emera

To the knowledge of Emera, there are no legal proceedings that individually or together could potentially involve claims against Emera or its subsidiaries for damages totaling 10% or more of the current assets of Emera, exclusive of interest and costs.

TECO Energy

From time to time, TECO Energy and its subsidiaries are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. TECO Energy believes the claims in which it or its subsidiary is a defendant in each of the pending actions described below are without merit and intends to defend each matter vigorously. TECO Energy is unable at this time to estimate the possible loss or range of loss with respect to these utilities. While the outcome of such proceedings is uncertain, management of TECO Energy does not believe that their ultimate resolution will have a material adverse effect on its results of operations, financial condition, or cash flows. Certain of such legal proceedings of TECO Energy and its subsidiaries are described below.

PGS Legal Proceedings

In November 2010, heavy equipment operated at a road construction site being conducted by Posen Construction, Inc. struck a natural gas line causing a rupture and ignition of the gas and an outage in the natural gas service to Lee and Collier counties, Florida. PGS filed suit in April 2011 against Posen Construction, Inc. in Federal Court for the Middle District of Florida to recover damages for repair and restoration relating to the incident and Posen Construction, Inc. counter-claimed against PGS alleging negligence. In the first quarter of 2014, the parties entered into a settlement agreement that resolves the claims of the parties. In addition, the suit filed in November 2011 by the Posen Construction, Inc. employee operating the heavy equipment involved in the incident in Lee County Circuit Court against PGS and a PGS contractor involved in the project, seeking damages for his injuries, remains pending, with a trial currently expected in October 2016.

NMGC Legal Proceedings

In February 2011, NMGC experienced gas shortages due to weather-related interruptions of electric service, weather-related problems on the systems of various interstate pipelines and in gas fields that are the sources of gas supplied to NMGC, and high weather-driven usage. This gas supply disruption and high usage resulted in the declaration of system emergencies by NMGC causing involuntary curtailments of gas utility service to approximately 28,700 customers (residential and business).

In March 2011, a customer purporting to represent a class consisting of all "32,000 [sic] customers" who had their gas utility service curtailed during the early-February system emergencies filed a putative class action lawsuit against NMGC. In March 2011, the Town of Bernalillo, New Mexico, purporting to represent a class consisting of all "New Mexico municipalities and governmental entities who have suffered damages as a result of the natural gas utility shut off" also filed a putative class action lawsuit against NMGC, four of its officers, and John and Jane Does at NMGC. In July 2011, the plaintiff in the Bernalillo class action filed an amended complaint to add an additional plaintiff purporting to represent a class of all similarly situated New Mexico private businesses and enterprises.

In September 2015, a settlement was reached with all the named plaintiff class representatives in both of the class actions. The settlements were on an individual basis and not a class basis. The settlements are not material to NMGC's financial position as of March 31, 2016.

In addition to the two settled class actions described above, 18 insurance carriers have filed two subrogation lawsuits for monies paid to their insureds as a result of the curtailment of natural gas service in February 2011. In January 2016, the judge entered summary judgement in favor of NMGC and all of the subrogation lawsuits were dismissed. The insurance carriers subsequently filed a timely appeal of the summary judgement, which is pending.

Proceedings in Connection with the Acquisition

Twelve securities class action lawsuits were filed against TECO Energy and its directors by holders of TECO Energy securities following the announcement of the Acquisition. Eleven suits were filed in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida. They alleged that TECO Energy's board of directors breached its fiduciary duties in agreeing to the Acquisition Agreement and sought to enjoin the Acquisition. In addition, several of these suits alleged that one or more of TECO Energy, Emera and an Emera affiliate aided and abetted such alleged breaches. The securities class action lawsuits have been consolidated per court order. Since the consolidation, two of the complaints have been amended. One of those complaints has added a claim against the individual defendants for breach of fiduciary duty to disclose. The twelfth suit was filed in the Middle District of Florida Federal Court and has subsequently been voluntarily dismissed.

TECO Energy also received two separate shareholder demand letters from purported shareholders of its stock. Both of these letters demanded that TECO Energy maximize shareholder value and remove alleged conflicts of interest as well as eliminate allegedly preclusive deal protection devices. One of the letters also demanded that TECO Energy refrain from consummating the transaction with Emera. Both of these demand letters have subsequently been withdrawn.

In November 2015, the parties to the lawsuits entered into a memorandum of understanding with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Acquisition. As a result of the memorandum of understanding, TECO Energy made additional disclosures related to the proposed Acquisition in a proxy supplement. Per the terms of the memorandum of understanding, the parties will negotiate a settlement agreement and submit it to the court for approval after the Acquisition is complete. There can be no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement.

Claim in connection with the Sale of TECO Coal

As discussed in Note 15 to TECO Energy's financial statements included in its 10-Q for the three months ended March 31, 2016, which are incorporated by reference herein, TECO Coal was sold on September 21, 2015 to Cambrian. On March 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified asserting breach of certain representations, and fraud and willful misconduct in connection therewith, of the TECO Coal SPA.

TECO Guatemala Holdings, LLC v. The Republic of Guatemala

On December 19, 2013, the International Centre for the Settlement of Investment Disputes ("ICSID") Tribunal hearing the arbitration claim of TECO Guatemala Holdings, LLC ("TGH"), a wholly owned subsidiary of TECO Energy, against the Republic of Guatemala (Guatemala) under the Dominican Republic Central America—United States Free Trade Agreement, issued an award in the case (the "Award"). The ICSID Tribunal unanimously found in favor of TGH and awarded damages to TGH of approximately U.S.$21.1 million, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus 2%. In addition, the ICSID Tribunal ruled that Guatemala must reimburse TGH for approximately U.S.$7.5 million of the costs that it incurred in pursuing the arbitration.

On April 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules.

Also on April 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the ICSID Tribunal's determination of the amount of TGH's damages.

On April 5, 2016, an ICSID ad hoc Committee issued a decision in favor of TGH in the annulment proceedings. In its decision, the ad hoc Committee unanimously dismissed Guatemala's application for annulment of the award and upheld the original U.S.$21.1 million award, plus interest. In addition, the ad hoc Committee granted TGH's application for partial annulment of the award, and ordered Guatemala to pay certain costs relating to the annulment proceedings. Because the ICSID Tribunal's award of costs to TGH in its original arbitration was based on the ICSID Tribunal's assessment that TGH had prevailed on liability and Guatemala had partially prevailed on damages, and the latter finding was annulled by the ad hoc Committee, the Committee also annulled the ICSID Tribunal's award of costs to TGH. As a result, TGH has the right to resubmit its arbitration claim against Guatemala to seek additional damages (in addition to the previously awarded U.S.$21.1 million), as well as additional interest on the U.S.$21.1 million, and its full costs relating to the original arbitration and the new arbitration proceeding. Results to date do not reflect any benefit of this decision.

PGS Compliance Matter

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS' implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On February 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to U.S.$3.9 million. On April 18, 2016, PGS reached a settlement regarding this matter with the OPC and FPSC staff and agreed to pay a $1 million civil penalty and customer refunds of $2 million. The FPSC approved the settlement agreement on May 5, 2016.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a PRP for certain Superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of March 31, 2016, TEC has estimated its ultimate financial liability to be U.S.$33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" on TEC's consolidated condensed balance sheets as of December 31, 2015. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer rates.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's allocated percentage share of the remediation costs.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

MANAGEMENT

Directors

The following information is provided for each Director of Emera as of the date hereof:

Name and Residence	Principal Occupations During the Past Five Years and Other Information	Director Since[1]
Sylvia D. Chrominska[7] Toronto, Ontario Canada	Former Group Head of Global Human Resources and Communications for the Bank of Nova Scotia, where she had global responsibility for human resources, corporate communications, government relations, public policy and corporate social responsibility of the Scotiabank Group. Former Chair of the Board of Scotia Group Jamaica Limited and Former Chair of the Board of Scotiabank Trinidad and Tobago Limited. A director of Wajax Corporation.	2010
Henry E. Demone[4] Lunenburg, Nova Scotia Canada	Chairman of High Liner Foods, the leading North American processor and marketer of value-added frozen seafood. Mr. Demone was President of High Liner Foods since 1989 and its President and Chief Executive Officer from 1992 to May 2015. A director of Saputo Inc.	2014
Allan L. Edgeworth[4] Calgary, Alberta Canada	Former President of ALE Energy Inc., a private consulting company. Former President and Chief Executive Officer of Alliance Pipeline. Director of AltaGas Ltd.	2005
James D. Eisenhauer Lunenburg, Nova Scotia Canada	President and Chief Executive Officer of ABCO Group Limited, which has holdings in manufacturing and distribution activities. Former Chair of the NSPI Board of Directors and director of NSPI since 2008.	2011
Christopher G. Huskilson Wellington, Nova Scotia Canada	President and Chief Executive Officer of Emera since November 2004. Director and former Chair of Emera Maine, Director of NSPI, Director of APUC and Chair or Director of a number of other Emera affiliated companies. Since June 1980, Mr. Huskilson has held a number of positions within NSPI and its predecessor, Nova Scotia Power Corporation.	2004
J. Wayne Leonard[2] New Orleans, Louisiana U.S.	Former Chairman and Chief Executive Officer of Entergy Corporation, an integrated electricity producer and retail distributor. Mr. Leonard joined Entergy Corporation as President and Chief Operating Officer in 1998, becoming CEO in 1999. Mr. Leonard serves on the Boards of the Edison Electric Institute and Tidewater, Inc. He has also served on the Board of the Centre for Climate and Energy Solutions.	2014
B. Lynn Loewen, FCPA, FCA[2] Westmount, Quebec Canada	President of Minogue Medical Inc. a healthcare organization which delivers innovative medical technologies to hospitals and clinics. President of Expertech Network Installation Inc. from 2008 to 2011.	2013

Name and Residence	Principal Occupations During the Past Five Years and Other Information	Director Since[1]
John T. McLennan[3] Mahone Bay, Nova Scotia Canada	Former Chair of the Board from May 2009 to May 2014. Former Board member of Chorus Aviation Inc. from January 2006 to May 2014. Former Chair of the Board of NSPI from May 2006 to May 2009. Former Vice-Chair and Chief Executive Officer of Allstream Inc. (formerly AT&T Canada). He is presently a Director of Amdocs Ltd.	2005
Donald A. Pether[2][5] Dundas, Ontario Canada	Former Chair of the Board and Chief Executive Officer of ArcelorMittal Dofasco Inc., a Canadian steel producer. Director of Samuel, Son & Co. Ltd. and Schlegel Health Care Inc.	2008
Andrea S. Rosen[6] Toronto, Ontario Canada	Former Vice-Chair of TD Bank Financial Group and President of TD Canada Trust. Director of Alberta Investment Management Corporation and Manulife Financial Corporation.	2007
Richard P. Sergel[3][4] Wellesley, Massachusetts U.S.	Former President and Chief Executive Officer of the North American Electric Reliability Corporation. Former President and Chief Executive Officer of National Grid USA from 2000 to 2004. Also former President and Chief Executive Officer of the New England Electric System. Presently a director of State Street Corporation. Has also served on the boards of the Edison Electric Institute and the Consortium for Energy Efficiency.	2010
M. Jacqueline Sheppard[8] Calgary, Alberta Canada	Chair of the Board since May 2014. Former Executive Vice President, Corporate and Legal of Talisman Energy Inc. Former Chair of the Research and Development Corporation of the Province of Newfoundland and Labrador, a provincial Crown Corporation. Founder and Lead Director of Black Swan Energy Inc., an Alberta upstream energy company that is private equity financed. Founder and former Director of Marsa Energy Inc., an oil and gas corporation. Director of Cairn Energy PLC, a publicly traded UK based international oil and gas producer. Director of the general partner of Pacific NorthWest LNG LP, which was formed for the purpose of constructing, owning and operating an LNG facility in British Columbia. Director of Seven Generations Energy Ltd.	2009

(1) Denotes the year the individual became a Director of Emera. Directors are elected for a one year term which expires at the termination of Emera's annual general meeting.
(2) Denotes member of the Audit Committee.
(3) Denotes member of the Nominating and Corporate Governance Committee.
(4) Denotes member of the Management Resources and Compensation Committee.
(5) Denotes Chair of the Nominating and Corporate Governance Committee.
(6) Denotes Chair of the Audit Committee.
(7) Denotes Chair of the Management Resources and Compensation Committee.
(8) Denotes Chair of the Board.

As of December 31, 2015, the Directors, in total, beneficially owned or controlled, directly or indirectly, approximately 43,439 common shares or less than 1% of the issued and outstanding shares of Emera.

There are no material conflicts of interest between Emera or any of its subsidiaries and any director or officer of Emera or any of its subsidiaries.

Officers

The Officers of Emera as of the date hereof are as follows:

Christopher G. Huskilson President and Chief Executive Officer Wellington, Nova Scotia Canada	President and Chief Executive Officer since November 1, 2004. From July 2003 to November 2004, Chief Operating Officer of Emera. Concurrently held the office of Chief Operating Officer of NSPI until January 2004. Prior to 2003, actively engaged for more than five years in the affairs of NSPI in various managerial and executive capacities.
Greg Blunden Chief Financial Officer Halifax, Nova Scotia Canada	Chief Financial Officer of Emera since March 2016. Prior to that, Vice-President, Corporate Strategy & Planning of Emera.
Scott C. Balfour Chief Operating Officer, Northeast and Caribbean Halifax, Nova Scotia Canada	Chief Operating Officer, Northeast & Caribbean since March 2016. Prior to that, Executive Vice President and Chief Financial Officer of Emera, appointed in April 2012. From September 2005 to January 2011, President and Chief Financial Officer of Aecon Group Inc., a Canadian publicly traded construction and infrastructure development company.
Nancy G. Tower, FCPA, FCA Chief Corporate Development Officer Halifax, Nova Scotia Canada	Chief Corporate Development Officer since May 2015. Before that, Executive Vice President Business Development from May 2011 to May 2015. From May 2011 to March 2014 CEO of Emera Newfoundland and Labrador. From November 2005 to May 2011, Executive Vice President and Chief Financial Officer. Prior to 2005, Vice-President Customer Operations for NSPI. From 1997 to 2000, Controller for NSPI.
R. Michael Roberts Chief Human Resources Officer Halifax, Nova Scotia Canada	Chief Human Resources Officer since December 1, 2014. Previously, President, Optimum Talent Atlantic of Halifax. Prior to that, Vice President, Corporate Development at Irving Shipbuilding and Vice President, Human Resources at Bell Aliant.
Bruce A. Marchand Chief Compliance Officer and Chief Legal Officer Halifax, Nova Scotia Canada	Chief Compliance Officer since December 1, 2014. Chief Legal Officer since January 2012. Prior to January 2012, Senior Partner at the law firm of McInnes Cooper.
Daniel P. Muldoon Executive Vice-President Major Renewables and Alternative Energy Halifax, Nova Scotia Canada	Executive Vice-President, Major Renewables and Alternative Energy since May 1, 2014. From June 16, 2011 to March 31, 2013, President and Chief Operating Officer, Emera Utility Services Inc. Prior to that, General Manager Engineering & Construction, Emera.

Wayne O'Connor Vice President, Corporate Strategy and Planning Halifax, Nova Scotia Canada	Vice President, Corporate Strategy & Planning for Emera since March 2016. Prior to that, Executive Vice President, Operations of NSPL.
Stephen D. Aftanas Corporate Secretary Halifax, Nova Scotia Canada	Corporate Secretary since September 2008. From June 2007 to September 2008, Associate Corporate Secretary. From March 2006 to June 2007, Associate General Counsel, NSPI. Prior to March 2006, Senior Solicitor, Emera.

THE ACQUISITION AGREEMENT

The Acquisition Agreement contains customary representations, warranties and covenants of TECO Energy, Emera and Merger Sub. The Acquisition Agreement contains covenants by TECO Energy, among others, that (i) TECO Energy will conduct its business in the ordinary course during the interim period between the execution of the Acquisition Agreement and the closing of the Acquisition and (ii) TECO Energy will not engage in certain transactions during such interim period. The Acquisition Agreement contains covenants by Emera, among others, that Emera will use its reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals.

In addition, the Acquisition Agreement requires Emera (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's headquarters in Tampa, Florida, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Acquisition, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those, that they received as of immediately prior to the closing.

TECO Energy is also subject to a "no shop" restriction that limits its ability to solicit alternative acquisition proposals or provide non-public information to, and engage in discussion with, third parties.

Either party may terminate the Acquisition Agreement if (i) the closing of the Acquisition has not occurred by September 30, 2016 (subject to a 6-month extension if required to obtain necessary regulatory approvals) or (ii) a law or judgment preventing or prohibiting the closing of the Acquisition has become final. If the Acquisition Agreement is terminated under certain circumstances, including the failure to obtain required regulatory approvals, Emera must pay TECO Energy a termination fee of US$326.9 million.

DESCRIPTION OF OTHER INDEBTEDNESS

Acquisition Capital Markets Transactions

In connection with financing the Acquisition, in addition to the offering by Emera of any series of Notes pursuant to one or more Prospectus Supplements, Emera U.S. Finance intends to issue Senior Guaranteed Notes. In addition, Emera intends to issue one or more series of Canadian dollar-denominated unsecured senior notes, and may also issue Canadian dollar-denominated unsecured subordinated notes, in each case, on a basis which is exempt from the prospectus requirements of applicable Canadian securities laws. Emera intends to raise up to approximately Cdn$6.6 billion in aggregate principal amount in the Acquisition Capital Markets Transactions. The aggregate principal amounts raised in the Acquisition Capital Markets Transactions are dependent on market and other conditions and may vary. Nothing contained herein shall be deemed to constitute an offer to sell or a solicitation of an offer to buy any of the securities to be issued in the Acquisition Capital Markets Transactions other than any Notes offered hereunder.

Proposed Emera U.S. Finance Senior Guaranteed Notes

As part of the Acquisition Capital Markets Transactions, Emera U.S. Finance intends to issue the Senior Guaranteed Notes. Emera U.S. Finance's business activities will consist solely of providing funds (directly or indirectly) to EUSHI and a wholly-owned subsidiary of Emera. The Senior Guaranteed Notes will be fully and unconditionally guaranteed (the "guarantees") by Emera and EUSHI (together, the "Guarantors").

The Senior Guaranteed Notes and the guarantees will be the senior unsecured indebtedness of Emera U.S. Finance and the Guarantors, respectively, ranking equally in right of payment with all existing and future unsubordinated, unsecured indebtedness of each of Emera U.S. Finance and the Guarantors, and senior in right of payment to all existing and future subordinated indebtedness of each of Emera U.S. Finance and the Guarantors including the Notes. The Senior Guaranteed Notes and the guarantees will be effectively junior in right of payment to all existing and future secured indebtedness (to the extent of the value of the assets securing such debt) of each of Emera U.S. Finance and the Guarantors. The indenture under which the Senior Guaranteed Notes will be issued (the "Senior Guaranteed Note Indenture") contains no restrictions on the amount of additional unsecured indebtedness Emera U.S. Finance or either of the Guarantors may incur or the amount of indebtedness (whether secured or unsecured) that their respective subsidiaries may incur. The Senior Guaranteed Note Indenture permits Emera U.S. Finance and the Guarantors to incur secured debt subject to certain covenants.

If Emera does not consummate the Acquisition on or prior to the later of: (i) December 31, 2016; and (ii) the date that is no later than June 30, 2017 if the close of the Acquisition has been extended by Emera or TECO Energy in accordance with the terms of the Acquisition Agreement (the "Special Mandatory Redemption Triggering Date") or the Acquisition Agreement is terminated at any time prior to the Special Mandatory Redemption Triggering Date, then Emera U.S. Finance will be required to redeem each of the outstanding series of Senior Guaranteed Notes on the Special Mandatory Redemption Date at a redemption price equal to 101% of the aggregate principal amount of the Senior Guaranteed Notes, plus accrued and unpaid interest, if any, up to, but excluding, the Special Mandatory Redemption Date.

Proposed Senior Notes

As part of the Acquisition Capital Markets Transactions, Emera intends to issue one or more series of Senior Notes in Canada on a basis which is exempt from the prospectus requirements of applicable Canadian securities laws.

The Senior Notes would be senior unsecured indebtedness of Emera, ranking equally in right of payment with all existing and future unsubordinated, unsecured indebtedness of Emera, and senior in right of payment to all existing and future subordinated indebtedness of Emera. The Senior Notes will be effectively junior in right of payment to all existing and future secured indebtedness (to the extent of the value of the assets securing such debt) of Emera. The indenture under which the Senior Notes would be issued (the "Senior Note Indenture") will contain no restrictions on the amount of additional unsecured indebtedness Emera may incur or the amount of indebtedness (whether secured or unsecured) that its subsidiaries may incur. The Senior Note Indenture would permit Emera to incur secured debt subject to certain covenants.

Proposed Canadian Dollar Subordinated Notes

As part of the Acquisition Capital Markets Transactions, Emera may issue Canadian Dollar Subordinated Notes having similar material attributes and characteristics to any Notes offered hereunder in Canada on a basis which is exempt from the prospectus requirements of applicable Canadian securities laws.

Convertible Debenture Offering

To finance a portion of the Acquisition, on September 28, 2015, Emera, through the Selling Debentureholder, completed the sale of $1.9 billion aggregate principal amount of Convertible Debentures, represented by instalment receipts. On October 2, 2015, in connection with the Convertible Debenture Offering, the underwriters fully exercised an overallotment option and purchased an additional $285 million aggregate principal amount of Convertible Debentures at the Convertible Debenture Offering price.

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing of the Convertible Debenture Offering or exercise of over-allotment option, as applicable, with the Final Instalment being payable on the Final Instalment Date.

Prior to the Final Instalment Date, the Convertible Debentures are represented by instalment receipts. The instalment receipts began trading on the TSX on September 28, 2015 under the symbol "EMA.IR." The Convertible Debentures are not listed. The Convertible Debentures will mature on September 29, 2025 and bear interest at an annual rate of 4.00% per $1,000 principal amount of Convertible Debentures until and including the Final Instalment Date, after which the interest rate will be 0.00%. Based on the first instalment of $333 per $1,000 principal amount of Convertible Debentures, the effective annual yield to and including the Final Instalment Date is 12%, and the effective annual yield thereafter is 0.00%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Convertible Debenture Offering, holders of Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, the Convertible Debenture Make-Whole Payment.

No Convertible Debenture Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Convertible Debenture Offering. Under the terms of the instalment receipt agreement, Emera agreed that until such time as the Convertible Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Company will at all times hold (on a consolidated basis) short-term U.S. dollar investment grade securities or have cash on hand (including the net proceeds of the first instalment of the Convertible Debenture Offering) of not less than the aggregate amount of the first instalment paid on the closing of the Convertible Debenture Offering and the exercise of the over-allotment option, in the event of a mandatory redemption.

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

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions precedent to the closing of the Acquisition will not be satisfied; (ii) termination of the Acquisition Agreement; and (iii) April 24, 2017, if notice of the Final Instalment Date has not been given to holders on or before April 21, 2017. Upon any such redemption, the Company will pay for each Convertible Debenture: (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the instalment receipt in satisfaction of the Final Instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by Emera at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. These costs will include a non-cash accounting charge for the difference between Emera's closing share price on the issuance date of the Convertible Debentures and their exercise price. This will be recognized once the contingencies surrounding regulatory and other approvals are resolved.

At maturity, Emera will repay the principal amount of any Convertible Debentures not converted and remaining outstanding in cash. Emera has the right to satisfy the obligation to repay the principal amount due in common shares, which will be valued at 95% of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment of the Convertible Debenture Offering are held and invested in short-term U.S. dollar investment grade securities. The net proceeds of the Final Instalment will be used, together with the net proceeds of the first instalment, to finance, directly or indirectly, the Acquisition and the Acquisition-Related Expenses. To mitigate the foreign currency translation risk associated with the Final Instalment, Emera entered into USD-denominated forward contracts, which are recorded on the consolidated balance sheets. The mark-to-market effect on these hedges is reported in the income statement and affects income, but is not reflected in adjusted net income.

Acquisition Credit Facilities

For purposes of financing the cash purchase price of the Acquisition, on September 4, 2015, Emera obtained commitment letters from JPMorgan Chase Bank, N.A., an affiliate of J.P. Morgan Securities LLC, and Scotiabank, an affiliate of Scotia Capital (USA) Inc., respectively, providing for non-revolving syndicated term credit facilities in favour of Emera in an aggregate amount of U.S.$6.5 billion (the "Acquisition Credit Facilities"). The Acquisition Credit Facilities consist of (i) a U.S.$4.3 billion bridge facility repayable in full on the first anniversary following its advance and (ii) a U.S.$2.2 billion bridge facility repayable in full on the first anniversary following its advance.

Emera is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common equity, preferred equity, bond or other debt offerings and any non-ordinary course asset sales by Emera and its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the Final Instalment under the Convertible Debentures and any offering of Notes and the other Acquisition Capital Markets Transactions, or from any such non-ordinary course asset sales or transactions, including Emera's sale of a portion of its ownership interest in APUC, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn.

The credit agreements pursuant to which the Acquisition Credit Facilities will be extended (the "Acquisition Credit Agreements") will contain certain prepayment options in favour of Emera and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Emera and certain of its subsidiaries (other than certain permitted equity or debt offerings subject to certain prescribed exceptions) and of any non-ordinary course asset sales (subject to certain prescribed exceptions) and certain other prescribed transactions will be required to be used to prepay the Acquisition Credit Facilities and any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements will contain customary representations and warranties and affirmative and negative covenants of Emera that will closely resemble those in the Revolving Facility as the same may be amended to reflect the

Acquisition. As part of these covenants, Emera will generally be required to maintain a consolidated debt to consolidated capitalization ratio of not more than 0.70:1.00. However, subject to prescribed circumstances Emera is permitted to maintain a consolidated debt to consolidated capitalization ratio of not more than 0.75:1.00. Any calculation of the consolidated debt to consolidated capitalization ratio on the date of the Acquisition shall be calculated on a pro forma basis after given effect to the Acquisition and related financings.

Customary fees are payable by Emera in respect of the Acquisition Credit Facilities and amounts outstanding under the Acquisition Credit Facilities will bear interest at market rates.

Revolving Facility

On May 30, 2016, Emera and two of its U.S. subsidiaries, as co-borrowers (together with any additional subsidiaries designated as co-borrowers from time to time, the "Revolver Borrowers"), entered into an amended and restated unsecured revolving credit facility (the "Revolving Facility") with The Bank of Nova Scotia, as administrative agent, and certain financial institutions, as lenders, under which the Revolver Borrowers may borrow up to $700 million or the equivalent amount in U.S. dollars, with a $50 million sublimit for a swingline facility available only for Canadian borrowers. The Revolving Facility includes a $200 million accordion option. Amounts borrowed may be repaid and re-borrowed until the maturity date (i.e., June 30, 2020), which can be extended for a further period of not more than 3 years, subject to satisfaction of certain conditions. The Revolving Facility includes representations, covenants, and events of default customary for financing transactions of this type, including a consolidated debt to consolidated capitalization maintenance ratio covenant of not more than 0.70:1.00 (which can be increased to 0.75:1.00 in prescribed circumstances). Borrowings under the Revolving Facility can be made in Canadian dollars (available to Canadian borrowers only) or U.S. dollars (available to all Revolver Borrowers). If a borrowing is made under the Revolving Facility, the interest rate will vary depending on the type of drawdown requested. If the loan is Base Rate advance (or, in the case of Canadian dollar loans, a Prime Rate advance), interest will be based on the relevant Base Rate or Prime Rate plus the applicable margin, which ranges between 0% and 0.70% (depending on Emera's long term debt rating from time to time). Interest on U.S. dollar loans that are LIBOR advances will be based on the LIBO Rate plus the applicable margin, which ranges between 0.80% and 1.70% (depending on Emera's long term debt rating from time to time). The Revolver Borrowers may also request Canadian dollar and U.S. dollar letters of credit under the Revolving Facility. As of March 31, 2016, Emera had a total of Cdn$276 million outstanding under the Revolving Facility.

Emera MTN Notes

On December 13, 2011, Emera issued Cdn$250 million of 2.96% senior unsecured notes due 2016 (the "Series H Senior Notes"). On November 30, 2009, Emera issued Cdn$225 million of 4.83% senior unsecured notes due 2019 (the "Series G Senior Notes," and together with the Series H Notes, the "Emera MTN Notes"). The Series H Senior Notes mature in December 2016 and the Series G Senior Notes mature in November 2019. The Emera MTN Notes were issued under Emera's $500,000,000 Debt Securities program.

The Emera MTN Notes are senior unsecured indebtedness of Emera, ranking equally in right of payment with all existing and future unsubordinated, unsecured indebtedness of Emera, and senior in right of payment to all existing and future subordinated indebtedness of Emera. The Emera MTN Notes are effectively junior in right of payment to all existing and future secured indebtedness (to the extent of the value of the assets securing such debt) of Emera. The trust indenture under which the Emera MTN Notes are issued (the "Emera MTN Indenture") contains no restrictions on the amount of additional unsecured indebtedness Emera may incur or the amount of indebtedness (whether secured or unsecured) that its subsidiaries may incur. The Emera MTN Indenture permits Emera to incur secured debt subject to compliance with a negative pledge covenant. The Emera MTN Notes are redeemable in whole or in part at any time, at the option of Emera, at make-whole redemption prices as set forth in the Emera MTN Indenture. The Emera MTN Indenture also contains customary events of default.

Emera Incorporated Subsidiary Debt

Certain of Emera's subsidiaries have indebtedness to which the Notes will be structurally subordinated. Some of this indebtedness is secured by the assets of or pledges of equity interests in certain of Emera's subsidiaries. As at March 31, 2016, Emera's subsidiaries had Cdn$2,247 million in indebtedness. For more information, see "Management's Discussion and Analysis—Developments—Recent Financing Activity."

DIVIDEND POLICY

Dividends on the Emera Common Shares are declared at the discretion of the Board of Directors. Emera paid per share cash dividends on the Emera Common Shares of $1.6600 in 2015, $1.4750 in 2014 and $1.4125 in 2013. In August 2015, Emera increased its annual dividend growth target from 6% to 8% through 2019 and the Board of Directors approved a 19% increase in its annual Common Share dividend from $1.60 to $1.90 per Emera Common Share.

Regular quarterly dividends at the prescribed rate have been paid on all of the First Preferred Shares, Series A, the First Preferred Shares, Series B, the First Preferred Shares, Series C, the First Preferred Shares, Series E and the First Preferred Shares, Series F.

DESCRIPTION OF THE NOTES

Notes

The following is a summary of the rights, privileges, restrictions, obligations and conditions attaching to the Notes and certain provisions of the Trust Indenture. This summary is qualified in its entirety by the provisions of the Trust Indenture. A copy of the form of Trust Indenture may be inspected during normal business hours at Emera's head office in Halifax, Nova Scotia, during the course of the distribution of the Notes. Following closing of any offering of Notes hereunder, a copy of the Trust Indenture will be available on SEDAR at www.sedar.com.

The specific terms of any offering of the Notes will be set forth in one or more prospectus supplements. You should read this Prospectus and any applicable Prospectus Supplement before you invest in any Notes.

For information concerning the Conversion Preferred Shares into which the Notes are, in certain circumstances, convertible as described under "—Automatic Conversion" below, see "Description of Conversion Preferred Shares".

Terms of the Notes

The Notes may be issued in one or more separate series. The Prospectus Supplement relating to the particular series of Notes being offered will specify the particular amounts, prices and terms of those Notes. These terms may include:

- the title of the Notes;
- any limit on the aggregate principal amount of the Notes of the series;
- the date on which the Notes will mature;
- the interest rate or rates, or the method of determining those rates;
- the date from which interest will accrue or the method for determining such date;
- the interest payment dates and the regular record dates;
- the places where payments will be made;
- any mandatory or optional redemption provisions;
- any additions to the events of default or covenants included in the Trust Indenture, as described in this Prospectus;
- if other than U.S. dollars, the currency or currencies, or units based on or related to currencies, in which payments on the Notes will be payable;
- whether the Notes will be issued in the form of a global security; and
- any other specific terms of the Notes.

Specified Denominations

The Notes will be issued only in minimum denominations of U.S.$2,000 and integral multiples of U.S.$1,000 in excess thereof.

Maturity Date

Each series of Notes will mature sixty (60) years from the date of issue (the "Maturity Date").

Interest

During the initial ten (10) year period following the issuance of any series of Notes, Emera will pay interest on such Notes at the rate specified in the applicable Prospectus Supplement in equal semi-annual installments.

Starting on the date which is ten (10) years from the date of issuance of any series of Notes, Emera will pay interest on such Notes on a quarterly basis in each year during which such Notes are outstanding thereafter until the Maturity Date (each such semi-annual or quarterly date, as applicable, an "Interest Payment Date").

From the date of issuance of any series of Notes to, but excluding, the date which is ten (10) years from the date of issuance of such Notes, the interest rate on such Notes will be fixed at the rate specified in the applicable Prospectus Supplement, payable in arrears. Starting on the date which is ten (10) years from the date of issuance of any series of Notes and on every quarterly period thereafter until the Maturity Date (each such date, an "Interest Reset Date"), the interest rate on such Notes will be reset at an interest rate per annum equal to the three month LIBOR plus an additional basis points margin as specified in the applicable Prospectus Supplement.

Deferral Right

So long as no event of default has occurred and is continuing, Emera may elect, at its sole option, at any date other than an Interest Payment Date (a "Deferral Date"), to defer the interest payable on any series of Notes on one or more occasions for up to five consecutive years (a "Deferral Period"). There is no limit on the number of Deferral Periods that may occur. Such deferral will not constitute an event of default or any other breach under the Trust Indenture and the Notes. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. A Deferral Period terminates on any interest payment date where Emera pays all accrued and unpaid interest on such date. No Deferral Period may extend beyond the maturity date of the series of Notes.

Emera will give the holders of the Notes written notice of its election to commence or continue a Deferral Period at least 10 and not more than 60 days before the next Interest Payment Date.

Dividend Stopper Undertaking

Unless Emera has paid all accrued and payable interest on any series of Notes, Emera will not:

(i) declare any dividend on the Dividend Restricted Shares or pay any interest on any Parity Notes (other than stock dividends on Dividend Restricted Shares);

(ii) redeem, purchase or otherwise retire any Dividend Restricted Shares or Parity Notes (except (i) with respect to Dividend Restricted Shares, out of the net cash proceeds of a substantially concurrent issue of Dividend Restricted Shares or (ii) pursuant to any purchase obligation, sinking fund, retraction privilege or mandatory redemption provisions attaching to any series of Dividend Restricted Shares); or

(iii) make any payment to holders of any of the Dividend Restricted Shares or any Parity Notes in respect of dividends not declared or paid on such Dividend Restricted Shares or interest not paid on such Parity Notes, respectively (the "Dividend Stopper Undertaking").

"Dividend Restricted Shares" means, collectively, the preferred shares of Emera (including the Conversion Preferred Shares) and the common shares of Emera.

"Parity Notes" means any class or series of Emera indebtedness currently outstanding or hereafter created which ranks on a parity with the Notes (prior to any Automatic Conversion (as defined below)) as to distributions upon liquidation, dissolution or winding-up.

It is in the interest of Emera to ensure that it timely pays interest on the Notes so as to avoid triggering the Dividend Stopper Undertaking.

Automatic Conversion

Each series of Notes, including accrued and unpaid interest thereon, will be converted automatically (the "Automatic Conversion"), without the consent of the holders thereof, into shares of a newly issued series of First Preferred Shares of Emera (the "Conversion Preferred Shares") upon the occurrence of: (i) the making by Emera of a general assignment for the benefit of its creditors or a proposal (or the filing of a notice of its intention to do so) under the *Bankruptcy and Insolvency Act* (Canada), (ii) any proceeding instituted by Emera seeking to adjudicate it a bankrupt or insolvent or, where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent, (iii) a receiver, interim receiver, trustee or other similar official is appointed over Emera or for any substantial part of its property and assets by a court of competent jurisdiction in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada; or (iv) any proceeding is instituted against Emera seeking to adjudicate it a bankrupt or insolvent, or where Emera is insolvent, seeking liquidation, winding up, dissolution, reorganization, arrangement, adjustment, protection, relief or composition of its debts under any law relating to bankruptcy or insolvency in Canada, or seeking the entry of an order for the appointment of a receiver, interim receiver, trustee or other similar official for Emera or any substantial part of its property and assets in circumstances where Emera is adjudged a bankrupt or insolvent under any law relating to bankruptcy or insolvency in Canada, and either such proceeding has not been stayed or dismissed within sixty (60) days of the institution of any such proceeding or the actions sought in such proceedings occur (including the entry of an order for relief against Emera or the appointment of a receiver, interim receiver, trustee, or other similar official for it or for any substantial part of its property and assets) (each, an "Automatic Conversion Event").

The Conversion Preferred Shares will carry the right to receive cumulative preferential cash dividends, if, as and when declared by the Board of Directors, subject to the Companies Act (Nova Scotia), at the Perpetual Preferred Share Rate, payable on each semi-annual or quarterly dividend payment date, as the case may be, subject to any applicable withholding tax. See "Description of Conversion Preferred Shares".

The Automatic Conversion shall occur upon an Automatic Conversion Event (the "Conversion Time"). As of the Conversion Time, each series of Notes shall be automatically converted, without the consent of the holders of the note, into a newly issued series of fully-paid Conversion Preferred Shares. At such time, such series of Notes shall be deemed to be immediately and automatically surrendered and cancelled without need for further action by noteholders, who shall thereupon automatically cease to be holders thereof and all rights of any such holder as a debtholder of Emera shall automatically cease. At the Conversion Time, holders of each series of Notes will receive one Conversion Preferred Share for each U.S.$1,000 principal amount of Notes previously held together with the number of Conversion Preferred Shares (including fractional shares, if applicable) calculated by dividing the amount of accrued and unpaid interest, if any, on the Notes, by U.S.$1,000.

Upon an Automatic Conversion of the Notes, Emera reserves the right not to issue some or all, as applicable, of the Conversion Preferred Shares to Ineligible Persons. In such circumstances, Emera will hold all Conversion Preferred Shares that would otherwise be delivered to Ineligible Persons, as agent for Ineligible Persons, and will attempt to facilitate the sale of such shares through a registered dealer retained by Emera for the purpose of effecting the sale (to parties other than Emera, its affiliates or other Ineligible Persons) on behalf of such Ineligible Persons of such Conversion Preferred Shares. Such sales, if any, may be made at any time and any price. Emera will not be subject to any liability for failing to sell Conversion Preferred Shares on behalf of any such Ineligible Persons or at any particular price on any particular day. The net proceeds received by Emera from the sale of any such Conversion Preferred Shares will be divided among the Ineligible Persons in proportion to the number of Conversion Preferred Shares that would otherwise have been delivered to them, after deducting the costs of sale and any applicable taxes, if any. Emera will make payment of the aggregate net proceeds to the

Clearing Agency (if the Notes are then held in the book-entry only system) or to the registrar and transfer agent (in all other cases) for distribution to such Ineligible Persons in accordance with the Clearing Agency Procedures or otherwise.

As a precondition to the delivery of any certificate or other evidence of issuance representing any Conversion Preferred Shares or related rights following an Automatic Conversion, Emera may obtain from any holder of Notes (and persons holding Notes represented by such holder of Notes) a declaration, in form and substance satisfactory to Emera, confirming compliance with any applicable regulatory requirements to establish that such holder of Notes is not, and does not represent, an Ineligible Person.

As the events that give rise to an Automatic Conversion are bankruptcy and related events, it is in the interest of Emera to ensure that an Automatic Conversion does not occur, although the events that could give rise to an Automatic Conversion may be beyond Emera's control.

Redemption Right

Except as may otherwise be provided in a Prospectus Supplement, on or after the date that is ten (10) years from the date of issuance of any series of Notes, Emera may, at its option, on giving not more than 60 nor less than 30 days' notice to the holders of such Notes , redeem the Notes, in whole at any time or in part from time to time on any Interest Payment Date. The redemption price per U.S.$1,000 principal amount of Notes redeemed on any Interest Payment Date will be 100% of the principal amount thereof, together with accrued and unpaid interest to, but excluding, the date fixed for redemption. Notes that are redeemed shall be cancelled and shall not be reissued.

Redemption on Tax or Rating Event

Except as may otherwise be provided in a Prospectus Supplement, prior to the initial Interest Reset Date and within 90 days of a Tax Event, Emera may, at its option, redeem all (but not less than all) of any series of Notes at a redemption price per U.S.$1,000 principal amount of such Notes equal to 100% of the principal amount thereof, together with accrued and unpaid interest to but excluding the date fixed for redemption.

Except as may otherwise be provided in a Prospectus Supplement, prior to the initial Interest Reset Date and within 90 days of a Rating Event, Emera may, at its option, redeem all (but not less than all) of any series of Notes at a redemption price per U.S.$1,000 principal amount of such Notes equal to 102% of the principal amount thereof, together with accrued and unpaid interest to but excluding the date fixed for redemption.

Additional Optional and Mandatory Redemption Events:

The Prospectus Supplement relating to a particular series of Notes being offered may also include additional optional redemption rights or mandatory redemption events.

Purchase for Cancellation

Subject to the Dividend Stopper Undertaking, the Notes may be purchased, in whole or in part, by Emera in the open market or by tender or private contract. Notes purchased by Emera shall be cancelled and shall not be reissued. The purchase price payable by Emera will be paid in cash.

Subordination

The Notes will be direct unsecured subordinated obligations of Emera. The payment of principal and interest on the Notes, to the extent provided in the Trust Indenture, will be subordinated in right of payment to the prior payment in full of all present and future Senior Indebtedness, and will be effectively subordinated to all indebtedness and obligations of Emera's subsidiaries.

"Senior Indebtedness" means obligations (other than non-recourse obligations, Notes issued under the Trust Indenture or any other obligations specifically designated as being subordinate in right of payment to Senior Indebtedness) of, or guaranteed or assumed by, Emera for borrowed money or evidenced by bonds, debentures or notes or obligations of Emera for or in respect of bankers' acceptances (including the face amount thereof), letters of credit and letters of guarantee (including all reimbursement obligations in respect of each of the forgoing) or other similar instruments, and amendments, renewal, extensions, modifications and refunding of any such indebtedness or obligation. As of March 31, 2016, Emera's Senior Indebtedness totaled approximately Cdn$751 million.

Events of Default

An event of default in respect of any series Notes will occur only if Emera defaults on the payment of (i) principal or premium, if any, when due and payable or (ii) interest when due and payable and such default continues for 30 days (subject to Emera's right, at its sole option, to defer interest payments, as described under "Description of the Notes—Deferred Right").

If an event of default has occurred and is continuing with respect to a series of Notes, and the Notes have not already been automatically converted into Conversion Preferred Shares, then Emera shall without notice from an Indenture Trustee be deemed to be in default under the Trust Indenture and the Notes and the Indenture Trustee may, in its discretion and shall upon the request of holders of not less than one-quarter of the principal amount of Notes of that series then outstanding under the Trust Indenture, demand payment of the principal or premium, if any, together with any accrued and unpaid interest up to (but excluding) such date, which shall immediately become due and payable in cash, and may institute legal proceedings for the collection of such aggregate amount where Emera fails to make payment thereof upon such demand.

Additional Emera Covenants

In addition to the Dividend Stopper Undertaking, Emera will covenant for the benefit of the holders of each series of Notes, that it will not create or issue any Emera Preferred Shares which, in the event of insolvency or winding-up of Emera, would rank in right of payment in priority to the Conversion Preferred Shares.

Issue of Conversion Preferred Shares in Connection with Automatic Conversion

All corporate action necessary to authorize Emera to issue Conversion Preferred Shares pursuant to the terms of the Notes will be completed prior to the closing of any offering of Notes.

Merger, Consolidation, Sale, Lease or Conveyance

The Trust Indenture provides that Emera will not merge, amalgamate or consolidate with any other person and will not sell, lease or convey all or substantially all its assets to any person, unless Emera shall be the continuing person, or unless the successor corporation or person that acquires all or substantially all the assets of Emera shall expressly assume all of the covenants to be performed and conditions to be observed by Emera under the Trust Indenture, and unless immediately after such merger, amalgamation, consolidation, sale, lease or conveyance, Emera, such person or such successor corporation shall not be in default in the performance of the covenants and conditions of such Trust Indenture to be performed or observed by Emera.

If such successor corporation or person that acquires all or substantially all the assets of Emera is organized under the laws of a jurisdiction other than the laws of Canada or any province of territory thereof or the United States, any state thereof or the District of Columbia, such successor corporation or person shall assume Emera's obligations under the Trust Indenture to pay Additional Amounts, with the name of such successor jurisdiction being included in addition to Canada in each place that Canada appears in "Payment of Additional Amounts".

Payment of Additional Amounts

All payments made by or on account of any obligation of Emera under or with respect to the Notes shall be made free and clear of and without withholding or deduction for, or on account of, any present or future tax, duty, levy, impost, assessment or other governmental charge (including penalties, interest and other liabilities related thereto) imposed or levied by or on behalf of the Government of Canada or any province or territory thereof or by any authority or agency therein or thereof having power to tax (hereinafter, "Canadian Taxes"), unless Emera is required to withhold or deduct Canadian Taxes by law or by the interpretation or administration thereof by the relevant government authority or agency. If Emera is so required to withhold or deduct any amount for or on account of Canadian Taxes from any payment made under or with respect to the Notes, Emera shall pay as additional interest such additional amounts (hereinafter "Additional Amounts") as may be necessary so that the net amount received by each holder of the Notes (including Additional Amounts) after such withholding or deduction shall not be less than the amount the holder of the Notes would have received if such Canadian Taxes had not been withheld or deducted; provided, however, that no Additional Amounts shall be payable with respect to a payment made to a holder of the Notes (hereinafter an "Excluded Holder") in respect of a beneficial owner (i) with which Emera does not deal at arm's length (for purposes of the Tax Act) at the time of the making of such payment, (ii) which is subject to such Canadian Taxes by reason of the failure to comply with any certification, identification, information, documentation or other reporting requirement by a holder of the Notes if compliance is required by law, regulation, administrative practice or an applicable treaty as a precondition to exemption from, or a reduction in, the rate of deduction or withholding of, such Canadian Taxes, (iii) where all or any portion of the amount paid to such holder of the Notes is deemed to be a dividend paid to such holder pursuant to subsection 214(16) of the Tax Act, or (iv) which is subject to such Canadian Taxes by reason of its carrying on business in or being connected with Canada or any province or territory thereof otherwise than by the mere holding of Notes or the receipt of payments thereunder. Emera shall make such withholding or deduction and remit the full amount deducted or withheld to the relevant authority as and when required under applicable law.

If a holder of the Notes has received a refund or credit for any Canadian Taxes with respect to which Emera has paid Additional Amounts, such holder of the Notes shall pay over such refund to Emera (but only to the extent of such Additional Amounts), net of all out of-pocket expenses of such holder of the Notes, together with any interest paid by the relevant tax authority in respect of such refund.

Amendment, Supplement and Waiver

The Trust Indenture or the Notes may be amended and any existing default or event of default or compliance with any provision of the Trust Indenture or any series of Notes may be waived by Extraordinary Resolution; provided that, in any case, without the consent of each holder of the outstanding series of Notes affected thereby, Emera and the Indenture Trustee may not (a) extend the stated maturity of the principal of the Notes of that series, (b) reduce the principal amount thereof or reduce the rate or extend the time of payment of interest thereon, (c) reduce any amount payable on redemption thereof, (d) change the place at which or currency in which principal and interest payments are to be made, (e) reduce the amount of any original issue discount security payable upon acceleration or provable in bankruptcy or impair the right to institute suit for the enforcement of any payment on any of the Notes of that series when due, or (f) reduce the aforesaid percentage in principal amount of the Notes of that series.

Issue of Additional Notes

Emera may, at any time and from time to time, issue additional Notes or other subordinated notes without the authorization of holders of any series of Notes. In the event that Emera issues additional series of subordinated notes, the rights, privileges, restrictions and conditions attached to such additional series may vary materially from other series of Notes. In such event, the right of the holders of any series of Notes to receive interest or principal may rank pari passu with the rights of the holders of other subordinated notes.

Governing Law

The Trust Indenture and the Notes will be governed by and construed in accordance with the laws of the Province of Nova Scotia and the federal laws of Canada applicable therein, other than such provisions of the Trust Indenture which govern American Stock Transfer & Trust Company, LLC's rights and obligations to holders of the Notes and Emera, which will be governed by the laws of the State of New York.

Book-Entry Only Form

Upon issuance, each series of Notes will be represented by one or more fully registered global securities (the "Global Securities") registered in the name of Cede & Co. (the nominee of The Depository Trust Company (the "Clearing Agency")), or such other name as may be requested by an authorized representative of the Clearing Agency. The authorized denominations of each Note will be U.S.$2,000 and integral multiples of U.S.$1,000 in excess thereof. Accordingly, the Notes may be transferred or converted only through the Clearing Agency and its participants. Except as described below, owners of beneficial interests in the Global Securities will not be entitled to receive the Notes in definitive form.

Beneficial interests in the Notes will be represented through book-entry accounts of financial institutions acting on behalf of beneficial owners as direct and indirect participants in the Clearing Agency. Holders of the Notes may elect to hold interests in the Notes in global form through either the Clearing Agency in the U.S. or Clearstream Banking, société anonyme ("Clearstream, Luxembourg"), or Euroclear Bank S.A./N.V. ("Euroclear"), if they are participants in those systems, or indirectly through organizations which are participants in those systems. Clearstream, Luxembourg and Euroclear will hold interests on behalf of their participants through customers' securities accounts in Clearstream, Luxembourg's and Euroclear's names on the books of their respective depositaries, which in turn will hold such interests in customers' securities accounts in the depositaries' names on the books of the Clearing Agency.

Each person owning a beneficial interest in a Global Security must rely on the procedures of the Clearing Agency and, if such person is not a participant, on the procedures of the participant through which such person owns its interest in order to exercise any rights of a holder under the Trust Indenture. The laws of some jurisdictions require that certain purchasers of securities take physical delivery of such securities in certificated form. Such limits and such laws may impair the ability to transfer beneficial interests in a Global Security representing the Notes.

The following is based on information furnished by the Clearing Agency:

The Clearing Agency is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act. The Clearing Agency holds securities that its participants ("Participants") deposit with the Clearing Agency. The Clearing Agency also facilitates the settlement among Participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in Participants' accounts, thereby eliminating the need for physical movement of securities certificates. These direct Participants ("Direct Participants") include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. The Clearing Agency is a wholly-owned subsidiary of the Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for the Clearing Agency, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the Clearing Agency's system is also available to others such as securities brokers and dealers, banks and trust companies that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The rules applicable to the Clearing Agency and its Participants are on file with the SEC.

Purchases of the Notes under the Clearing Agency's system must be made by or through Direct Participants, which will receive a credit for such Notes on the Clearing Agency's records. The ownership interest of each actual purchaser of each Note represented by a Global Security ("Beneficial Owner") is in turn to be recorded on the Direct Participants' and Indirect Participants' records. Beneficial Owners will not receive written confirmation from the Clearing Agency of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct Participants or Indirect Participants through which such Beneficial Owner entered into the transaction. Transfers of ownership interests in a Global Security representing the Notes are to be accomplished by entries made on the books of Participants acting on behalf of Beneficial Owners. Beneficial Owners of a Global Security representing the Notes will not receive the Notes in definitive form representing their ownership interests therein, except in the event that use of the book-entry system for such Notes is discontinued.

To facilitate subsequent transfers, the Global Securities representing the Notes which are deposited with the Clearing Agency are registered in the name of the Clearing Agency's nominee, Cede & Co., or such other name as may be requested by an authorized representative of the Clearing Agency. The deposit of Global Securities with the Clearing Agency and their registration in the name of Cede & Co. or such other nominee effect no change in beneficial ownership. The Clearing Agency has no knowledge of the actual Beneficial Owners of the Global Securities representing the Notes; the Clearing Agency's records reflect only the identity of the Direct Participants to whose accounts such Notes are credited, which may or may not be the Beneficial Owners. The Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by the Clearing Agency to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Neither the Clearing Agency nor Cede & Co. (nor such other nominee of the Clearing Agency) will consent or vote with respect to the Global Securities representing the Notes. Under its usual procedures, the Clearing Agency mails an "omnibus proxy" to Emera as soon as possible after the applicable record date. The omnibus proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Notes are credited on the applicable record date (identified in a listing attached to the omnibus proxy).

Principal, premium, if any, and interest payments on the Global Securities representing the Notes will be made to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Clearing Agency). The Clearing Agency's practice is to credit Direct Participants' accounts, upon the Clearing Agency's receipt of funds and corresponding detailed information from Emera or the Indenture Trustee, on the applicable payment date in accordance with their respective holdings shown on the Clearing Agency's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of such Participant and not of the Clearing Agency, the applicable Indenture Trustee or Emera, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal, premium, if any, and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Clearing Agency) is the responsibility of Emera or the applicable Indenture Trustee (provided it has received funds from Emera), disbursement of such payments to Direct Participants shall be the responsibility of the Clearing Agency, and disbursement of such payments to the Beneficial Owners shall be the responsibility of Direct and Indirect Participants.

The Clearing Agency may discontinue providing its services as securities depository with respect to the Notes at any time by giving reasonable notice to Emera or the Indenture Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Notes in definitive form are required to be printed and delivered to each holder.

Emera may decide to discontinue use of the system of book-entry transfers through the Clearing Agency (or a successor securities depositary). In that event, the Notes in definitive form will be printed and delivered.

Clearstream, Luxembourg advises that it is incorporated under the laws of Luxembourg as a professional depositary. Clearstream, Luxembourg holds securities for its participating organizations ("Clearstream participants"), and facilitates the clearance and settlement of securities transactions between Clearstream participants through electronic book-entry changes in accounts of Clearstream participants, thereby eliminating the need for physical movement of certificates. Clearstream, Luxembourg provides to Clearstream participants, among other things, services for safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Clearstream, Luxembourg interfaces with domestic markets in several countries. As a professional depositary, Clearstream, Luxembourg is subject to regulation by the Luxembourg Commission for the Supervision of the Financial Sector (Commission de Surveillance du Secteur Financier). Clearstream participants are recognized financial institutions around the world, including underwriters, securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations and may include the underwriters of an offering of Notes. Indirect access to Clearstream, Luxembourg is also available to others, such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Clearstream participant, either directly or indirectly.

Distributions with respect to interests in the Notes held beneficially through Clearstream, Luxembourg will be credited to cash accounts of Clearstream participants in accordance with its rules and procedures, to the extent received by the Clearing Agency for Clearstream, Luxembourg.

Euroclear advises that it was created in 1968 to hold securities for participants of Euroclear ("Euroclear participants"), and to clear and settle transactions between Euroclear participants through simultaneous electronic book-entry delivery against payment, thereby eliminating the need for physical movement of certificates and any risk from lack of simultaneous transfers of securities and cash. Euroclear includes various other services, including securities lending and borrowing and interfaces with domestic markets in several countries. Euroclear is operated by Euroclear Bank S.A./N.V. ("Euroclear Operator"). All operations are conducted by the Euroclear Operator, and all Euroclear securities clearance accounts and Euroclear cash accounts are accounts with the Euroclear Operator. Euroclear participants include banks (including central banks), securities brokers and dealers and other professional financial intermediaries and may include the underwriters of an offering of Notes. Indirect access to Euroclear is also available to other firms that clear through or maintain a custodial relationship with a Euroclear participant, either directly or indirectly.

Securities clearance accounts and cash accounts with the Euroclear Operator are governed by the Terms and Conditions Governing Use of Euroclear and the related Operating Procedures of the Euroclear System, and applicable Belgian law (collectively, the "Terms and Conditions"). The Terms and Conditions govern transfers of securities and cash within the Euroclear System, withdrawals of securities and cash from the Euroclear System, and receipts of payment with respect to securities in the Euroclear System. All securities in the Euroclear System are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts. The Euroclear Operator acts under the Terms and Conditions only on behalf of Euroclear participants, and has no records of or relationship with persons holding through Euroclear participants.

Distributions with respect to the Notes held beneficially through the Euroclear System will be credited to the cash accounts of Euroclear participants in accordance with the Terms and Conditions, to the extent received by the U.S. depositary for the Euroclear System.

The information in this section concerning the Clearing Agency and the Clearing Agency's book-entry system, Clearstream, Luxembourg and Euroclear has been obtained from sources that Emera believes to be reliable, but is subject to any changes to the arrangements between Emera and the Clearing Agency and any changes to such procedures that may be instituted unilaterally by the Clearing Agency, Clearstream, Luxembourg and Euroclear.

Transfers

Transfers of ownership of the Notes will be effected only through records maintained by the Clearing Agency for such Notes with respect to interests of Participants and on the records of Participants with respect to interests of persons other than Participants. Holders of the Notes who are not Participants, but who desire to purchase, sell or otherwise transfer ownership of or other interests in the Notes, may do so only through Participants. The ability of a holder to pledge Notes or otherwise take action with respect to such holder's interest in Notes (other than through a Participant) may be limited due to the lack of a physical certificate. See "Risk Factors—Risks Related to the Notes—Liquidity of and Dealings in Notes".

Payments and Deliveries

As long as the Clearing Agency is the registered owner of the Notes, the Clearing Agency will be considered the sole owner of the Notes for the purposes of receiving payments on the Notes or the delivery of Conversion Preferred Shares upon the occurrence of an Automatic Conversion. Payments of interest in respect of Notes will be made by Emera to the Clearing Agency as the registered holder of the Notes and Emera understands that such payments will be forwarded by the Clearing Agency to Participants in accordance with the Clearing Agency Procedures. Deliveries of Conversion Preferred Shares in respect of the exercise or operation of the Automatic Conversion in the limited circumstances described under "—Automatic Conversion" will be made by Emera to the Clearing Agency as the registered holder of the Notes and Emera understands that such shares will be forwarded by the Clearing Agency to Participants in accordance with the Clearing Agency Procedures. As long as the Notes are held in the Clearing Agency book-entry only system, the responsibility and liability of the Indenture Trustee and/or Emera in respect of the Notes is limited to making payment of any amount due on the Notes and/or making delivery of Conversion Preferred Shares in respect thereof to the Clearing Agency.

DESCRIPTION OF CONVERSION PREFERRED SHARES

The following is a summary of the rights, privileges, restrictions and conditions attaching to each series of Conversion Preferred Shares. This summary is qualified in its entirety by Emera's memorandum of association, as amended, and articles of association, as amended, and the actual terms and conditions of each series of Conversion Preferred Shares.

The specific terms of any offering of the Conversion Preferred Shares will be set for in one or more Prospectus Supplements. You should read this Prospectus and any applicable Prospectus Supplement before you invest in any Notes or Conversion Preferred Shares.

Issue Price

The Conversion Preferred Shares will have an issue price of U.S.$1,000 per share.

No Fixed Maturity

The Conversion Preferred Shares will not have a fixed maturity date.

Dividends

Holders of each series of Conversion Preferred Shares will be entitled to receive cumulative preferential cash dividends, if, as and when declared by the Board of Directors, subject to the Companies Act (Nova Scotia), at the same rate as would have accrued on the related series of Notes (had such Notes remained outstanding) as described under "Description of the Notes—Interest") (the "Perpetual Preferred Share Rate"), payable on each semi-annual or quarterly dividend payment date, as the case may be, subject to applicable withholding tax. If the Board of Directors does not declare the dividends, or any part thereof, on the Conversion Preferred Shares on or before the dividend payment date for a particular period, such dividend or the unpaid part thereof shall be paid on a subsequent date or dates to be determined by the Board of Directors on which Emera shall have sufficient monies properly available, under the provisions of applicable law and under the provisions of any trust indenture governing bonds, debentures or other securities of Emera, for the payment of the same.

Redemption of the Conversion Preferred Shares

The Prospectus Supplement relating to the related series of Notes being offered will specify any mandatory or optional redemption terms of the Conversion Preferred Shares.

Presentation for Redemption or Sale

A redemption or sale to Emera of Conversion Preferred Shares will be effected by the holder transferring such holder's Conversion Preferred Shares to be redeemed or sold to the account of Emera in the Clearing Agency (or, in the event that the Conversion Preferred Shares are not then issued in book-entry only form, by depositing with the transfer agent for the Conversion Preferred Shares, at one of its principal offices, certificates representing such Conversion Preferred Shares).

Purchase for Cancellation

The Prospectus Supplement relating to the related series of Notes being offered will specify any repurchase entitlement of the series of Conversion Preferred Shares relating to the related series of Notes being offered.

Rights on Liquidation

In the event of the liquidation, dissolution or winding-up of Emera, the holders of the Conversion Preferred Shares shall be entitled to receive U.S.$1,000 per share (less any amount that may have been returned to holders as a return of capital), together with all accrued and unpaid dividends thereon, subject to any applicable withholding tax, before any amount shall be paid or any assets of Emera distributed to the holders of Common Shares or any shares ranking junior to the Conversion Preferred Shares. The holders of the Conversion Preferred Shares shall not be entitled to share in any further distribution of the property or assets of Emera.

Restrictions on Dividends and Retirement of Conversion Preferred Shares

So long as any of the Conversion Preferred Shares of any series are outstanding, Emera will not, without the approval of the holders of the Conversion Preferred Shares of that series, given as specified below:

(i) declare any dividend on the Common Shares or any other shares ranking junior to the Conversion Preferred Shares (other than stock dividends on shares ranking junior to the Conversion Preferred Shares); or

(ii) redeem, purchase or otherwise retire any Common Shares or any other shares ranking junior to the Conversion Preferred Shares (except out of the net cash proceeds of a substantially concurrent issue of shares ranking junior to the Conversion Preferred Shares); or

(iii) redeem, purchase or otherwise retire: (i) less than all the Conversion Preferred Shares; or (ii) except pursuant to any purchase obligation, sinking fund, retraction privilege or mandatory redemption provisions attaching to any series of preferred shares of Emera, any other shares ranking on a parity with the Conversion Preferred Shares;

unless, in each case, all dividends on the Conversion Preferred Shares of that series and on all other shares ranking prior to or on a parity with the Conversion Preferred Shares of that series, have been declared and paid or set apart for payment.

Issue of Additional Series of Emera Preferred Shares

Emera may issue other series of Emera Preferred Shares without the authorization of the holders of the Conversion Preferred Shares, as applicable.

Shareholder Approvals

The approval of any amendments to the rights, privileges, restrictions and conditions attaching to the Conversion Preferred Shares of any series may be given by a resolution carried by the affirmative vote of not less than 66 2/3% of the votes cast at a meeting of holders of Conversion Preferred Shares at which at least a majority of the outstanding Conversion Preferred Shares of that series is represented or, if no quorum is present at such meeting, at a meeting following such adjourned meeting at which no quorum requirement would apply. Emera will covenant that for so long as the Notes of any series are outstanding no amendment will be made to the rights, privileges, restrictions and conditions of the Conversion Preferred Shares of that series (other than any amendments relating to the Emera Preferred Shares as a class) without the prior approval of the holders of the Notes related to such series by Extraordinary Resolution.

Voting Rights

The voting rights of holders of any series of Conversion Preferred Shares shall be the same as the voting rights of the holders of Emera's other outstanding series of First Preferred Shares.

The holders of any series of Conversion Preferred Shares will not be entitled to receive notice of or to attend or to vote at any meeting of the shareholders of Emera unless and until Emera shall fail to pay in aggregate eight quarterly dividends on the Conversion Preferred Shares of that series, whether or not consecutive and whether or not dividends have been declared and whether or not there are any monies of Emera properly applicable to the payment of dividends. In that event, the holders of the Conversion Preferred Shares of that series will be entitled to receive notice of, and to attend, all meetings of shareholders at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at such meeting. Such entitlement to vote shall be exercised together with holders of shares of all other series of First Preferred Shares and all other classes or series of classes of shares of the Company bearing the right to vote in similar circumstances. In any such instance, a holder of Conversion Preferred Shares will be entitled to one vote for each share held, subject to the circumstances described below under "Constraints on Share Ownership". The voting rights of the holders of any series of Conversion Preferred Shares shall forthwith cease upon payment by Emera of all arrears of dividends on any outstanding Conversion Preferred Shares of that series unless and until eight quarterly dividends on such Conversion Preferred Shares shall again be in arrears and unpaid.

Constraints on Share Ownership

As required by the *Nova Scotia Power Reorganization (1998) Act* (Nova Scotia) and pursuant to the *Nova Scotia Power Privatization Act* (Nova Scotia), the Articles of Association of Emera (the "Emera Articles") provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, or vote, in the aggregate, voting shares of Emera to which are attached more than 15% of the votes attached to all outstanding voting shares of Emera. Non-residents of Canada may not subscribe for, have transferred to them, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, or vote, in the aggregate, voting shares of Emera to which are attached more than 25% of the votes attached to all outstanding voting shares of Emera. Votes cast by non-residents on any resolution at a meeting of common shareholders of Emera will be pro-rated so that such votes will not constitute more than 25% of the total number of votes cast.

The Common Shares, and in certain circumstances the First Preferred Shares, Series A, First Preferred Shares, Series B, First Preferred Shares, Series C, First Preferred Shares, Series E and First Preferred Shares, Series F, are considered to be voting shares for purposes of the constraints on share ownership, and any Conversion Preferred Shares issued upon an Automatic Conversion Event will also in certain circumstances be considered to be voting shares for purposes of the constraints on share ownership.

The Emera Articles contain provisions for the enforcement of these constraints on share ownership including provisions for suspension of voting rights, forfeiture of dividends, prohibitions of share transfer and issuance, compulsory sale of shares and redemption, and suspension of other shareholder rights. The Board of Directors may require shareholders to furnish statutory declarations as to matters relevant to enforcement of the restrictions.

Tax Election

The Conversion Preferred Shares will be "taxable preferred shares" as defined in the Tax Act for purposes of the tax under Part IV.1 of the Tax Act. The terms of the Conversion Preferred Shares will require Emera to make the necessary election under Part VI.1 of the Tax Act so that corporate holders will not be subject to the tax under Part IV.1 of the Tax Act on dividends received (or deemed to be received) on the Conversion Preferred Shares. See "Certain Canadian Federal Income Tax Considerations".

Book-Entry Only Form

Unless Emera elects otherwise, the Conversion Preferred Shares will be issued in "book-entry only" form and may be purchased, held and transferred in substantially the same manner as the Notes. See "Description of the Notes—Book-Entry Only Form".

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to Emera, the following is a summary of the principal Canadian federal income tax considerations generally applicable to a holder of Notes who acquires Notes under any offering hereunder and who, for purposes of the Tax Act and at all relevant times, (i) is not, and is not deemed to be, resident in Canada; (ii) deals at arm's length with and is not affiliated with Emera or any of its affiliates; (iii) deals at arm's length with any transferee resident (or deemed to be resident) in Canada to whom the Holder disposes of a Note; (iv) holds Notes and any Conversion Preferred Shares as capital property; (v) does not use or hold the Notes or Conversion Preferred Shares in a business carried on in Canada; and (vi) is not a "specified non-resident shareholder" of Emera for purposes of the Tax Act or a non-resident person not dealing at arm's length with a "specified shareholder" (within the meaning of subsection 18(5) of the Tax Act) of Emera (a "Non-Resident Holder"). Special rules, which are not discussed in this summary, may apply to certain Non-Resident Holders that are insurers carrying on an insurance business in Canada and elsewhere. This summary assumes that no interest paid on the Notes will be in respect of a debt or other obligation to pay an amount to a person with whom Emera does not deal at arm's length within the meaning of the Tax Act.

This summary is based upon the current provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Tax Proposals") and counsel's understanding of the administrative policies and assessing practices of the CRA published in writing prior to the date hereof. This summary is not exhaustive of all Canadian federal income tax considerations and, except for the Tax Proposals, does not take into account or anticipate any changes in law or CRA administrative policies and assessing practices, whether by way of legislative, governmental or judicial decision or action, nor does it take into account or consider any other federal tax considerations or any provincial, territorial or foreign tax considerations, which may differ materially from those discussed herein. While this summary assumes that the Tax Proposals will be enacted in the form proposed, no assurance can be given that such proposals will be enacted in their current form, or at all.

Generally, for purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of Notes or Conversion Preferred Shares must be determined in Canadian dollars. Any such amount that is expressed or denominated in a currency other than Canadian dollars must be converted into Canadian dollars using the relevant exchange rate determined in accordance with the Tax Act.

This summary is of a general nature only and is not, and is not intended to be, and should not be construed to be, legal or tax advice to any particular Non-Resident Holder and no representation with respect to the income tax consequences to any particular Non-Resident Holder is made. Prospective purchasers of Notes should consult their own tax advisors with respect to the tax consequences of acquiring, holding and disposing of Notes having regard to their own particular circumstances.

Notes

Interest on and disposition of the Notes

Under the Tax Act, interest, principal and premium, if any, paid or credited, or deemed to be paid or credited to a Non-Resident Holder on Notes will be exempt from Canadian non-resident withholding tax. No other taxes on income (including taxable capital gains) will be payable under the Tax Act in respect of the acquisition, holding, redemption or disposition of Notes, or the receipt of interest, premium or principal thereon by a Non-Resident Holder solely as a consequence of such acquisition, holding, redemption or disposition of Notes.

Automatic Conversion

A conversion of Notes into Conversion Preferred Shares pursuant to an Automatic Conversion will result in a disposition of such Notes for purposes of the Tax Act for proceeds equal to the fair market value of the Conversion Preferred Shares which the Non-Resident Holder acquires, not including any amount considered to be interest. A Non-Resident Holder will not generally be subject to tax under the Tax Act in respect of such disposition. The aggregate cost to a Non-Resident Holder of the Conversion Preferred Shares ultimately received on an Automatic Conversion will be equal to the fair market value thereof at the time received.

Conversion Preferred Shares

Dividends

A dividend (including a deemed dividend) received on Conversion Preferred Shares by a Non-Resident Holder will generally be subject to Canadian non-resident withholding tax under the Tax Act at a rate of 25 percent, subject to any reduction in the rate of such withholding under the provisions of an income tax treaty or convention. For a Non-Resident Holder who is a resident of the United States and qualifies for the benefits of the *Canada- United States Tax Convention*, the rate of withholding will generally be reduced to 15 percent or such other applicable rate pursuant to the income tax treaty.

Dispositions

A Non-Resident Holder of Conversion Preferred Shares who disposes of or is deemed to dispose of Conversion Preferred Shares (other than as discussed under "*Redemption or Other Acquisition by Emera*") will not be subject to tax in respect of any capital gain realized on a disposition of Conversion Preferred Shares unless the Conversion Preferred Shares constitute "taxable Canadian property" (as defined in the Tax Act) to the Non-Resident Holder at the time of the disposition and the Non-Resident Holder is not entitled to relief under an applicable income tax treaty or convention. The Conversion Preferred Shares will be considered taxable Canadian property if such shares are not listed on a designated stock exchange and, at any time during the 60-month period immediately preceding the disposition, the Conversion Preferred Shares derived (directly or indirectly) more than 50 percent of their fair market value from real or immovable property situated in Canada, Canadian resource properties, timber resource properties or options or interests in respect of any such property, all as defined for the purposes of the Tax Act.

If the Conversion Preferred Shares are considered taxable Canadian property to the Non-Resident Holder, a disposition or deemed disposition of such Conversion Preferred Shares (other than as discussed under *"Redemption or Other Acquisition by Emera"*) will generally give rise to a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of such Conversion Preferred Shares, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base of such Conversion Preferred Shares to the Non-Resident Holder. Generally, one half of any such capital gain must be included in the Non-Resident Holder's income for that year and one half of any such capital loss must be deducted against taxable capital gains realized in that year from dispositions of taxable Canadian property. Certain excess allowable capital losses from the dispositions of taxable Canadian property may be claimed in any of the three preceding taxation years or any subsequent taxation year subject to the rules contained in the Tax Act.

An applicable income tax treaty or convention may apply to exempt a Non- Resident Holder from tax under the Tax Act in respect of a disposition of Conversion Preferred Shares notwithstanding that such shares may constitute taxable Canadian property.

Redemption or Other Acquisition by Emera

If Emera redeems for cash or otherwise acquires the Conversion Preferred Shares, other than by a purchase in the manner in which shares are normally purchased by a member of the public in the open market, the Non-Resident Holder will be deemed to have received a dividend equal to the amount, if any, paid by Emera in excess of the paid-up capital of such shares for purposes of the Tax Act at such time. Such deemed dividend will be subject to the treatment described above under "Dividends". The difference between the amount paid and the amount of the deemed dividend will be treated as proceeds of disposition for the purposes of computing the capital gain or capital loss arising on a disposition of such shares.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

This disclosure is limited to the U.S. federal tax issues addressed herein. Additional issues may exist that are not addressed in this disclosure and that could affect the U.S. federal tax treatment of the Notes. Prospective investors should seek their own advice based on their particular circumstances from independent tax advisers.

The following are certain U.S. federal income tax consequences to the U.S. Holders (described below) of owning and disposing of the Notes purchased in any offering hereunder at the "issue price," which is the first price at which a substantial amount of the Notes is sold to the public, and held as capital assets for U.S. federal income tax purposes. This discussion does not describe all of the tax consequences that may be relevant to you in light of your particular circumstances, including alternative minimum tax and Medicare contribution tax consequences, as well as differing tax consequences that may apply if you are, for instance:

- a financial institution;
- a regulated investment company;
- a dealer or trader in securities that uses a mark-to-market method of tax accounting;
- holding the Notes as part of a "straddle" or integrated transaction;
- a person whose functional currency is not the U.S. dollar;
- a tax-exempt entity; or
- a partnership for U.S. federal income tax purposes.

If you are a partnership for U.S. federal income tax purposes, the U.S. federal income tax treatment of you and your partners will generally depend on the status of the partners and your activities. If you are a partnership owning the Notes or a partner in such partnership, you should consult your tax adviser as to your particular U.S. federal income tax consequences of owning the Notes. This discussion is based on the Internal Revenue Code of 1986, as amended, or the Code, administrative pronouncements, judicial decisions and final, temporary and proposed Treasury regulations, changes to any of which subsequent to the date of this document may affect the tax consequences described herein. This discussion does not address any aspect of state, local or non-U.S. taxation, or any taxes other than income taxes.

You should consult your tax adviser with regard to the application of the U.S. federal tax laws to your particular situation, as well as any tax consequences arising under the laws of any state, local or non-U.S. taxing jurisdiction.

You are a U.S. Holder for purposes of this discussion if for U.S. federal income tax purposes you are a beneficial owner of a Note or a Conversion Preferred Share and are:

- a citizen or individual resident of the United States;
- a corporation, or other entity taxable as a corporation, created or organized in or under the laws of the United States, any state therein or the District of Columbia; or
- an estate or trust the income of which is subject to U.S. federal income taxation regardless of its source.

Tax Treatment of the Notes

The determination of whether an obligation represents a debt or equity interest is based on all the relevant facts and circumstances at the time the obligation is issued. There is no direct legal authority as to the proper U.S. federal income tax treatment of an instrument such as the Notes that is denominated as a debt instrument and has certain debt features, but that provides for a possible Automatic Conversion under which an investor could lose its creditor rights upon the occurrence of an Automatic Conversion Event. In the absence of authority addressing the proper characterization of instruments such as the Notes, to the extent required to do so, we intend to treat the Notes as debt for U.S. federal income tax purposes. However, we will not request any ruling from the IRS regarding the treatment of the Notes for U.S. federal income tax purposes and the IRS or a court may conclude that the Notes should be treated as equity for U.S. federal income tax purposes (as described below). Prospective investors should consult their tax advisers as to the proper characterization of the Notes for U.S. federal income tax purposes.

Consequences if the Notes are Treated as Debt Instruments for U.S. Federal Income Tax Purposes

Assuming the treatment of the Notes as debt instruments for U.S. federal income tax purposes is respected, the following U.S. federal income tax consequences should result.

Certain Additional Payments

There are circumstances in which we might be required to make payments on a Note that would increase the yield of the Note, for instance, as described under "Description of the Notes—Redemption on Rating Event or Tax Event." We believe that the likelihood that we would be required to make such payments is "remote," and/or that the amount of any such payments, if made, would be "incidental," in each case within the meaning of the applicable Treasury Regulations. Therefore, we intend to take the position that the possibility of such payments does not result in the Notes being treated as contingent payment debt instruments under the applicable Treasury Regulations. If the IRS takes a contrary position, you may be required to accrue interest income based upon a "comparable yield" (as defined in the Treasury Regulations) determined at the time of issuance of the Notes, with adjustments to such accruals when any contingent payments are made that differ from the payments based on the comparable yield. In addition, any income on the sale or other taxable disposition of the Notes would be treated as interest income rather than as capital gain. You should consult your tax adviser regarding the tax consequences if the Notes were treated as contingent payment debt instruments. The remainder of this discussion assumes that the Notes are not treated as contingent payment debt instruments.

Payments of Interest

Based on current market conditions, and subject to the discussion below relating to our option to defer payments of interest on the Notes, we expect, and this discussion assumes, that the Notes will be issued without original issue discount for U.S. federal income tax purposes.

Under the terms of the Notes, we have the ability to defer payments of interest from time to time for up to five years. United States Treasury Regulations provide that a debt instrument will not be treated as issued with original issue discount, or OID, by reason of its issuer's ability to defer payments of interest if the likelihood of such deferral is "remote." We intend to take the position, and this discussion assumes, that, as of the date of this Prospectus, the likelihood of deferring payments of interest under the terms of the Notes is "remote" within the meaning of the Treasury Regulations referred to above. Based on the foregoing, we do not intend to treat the Notes as issued with OID by reason of our deferral option. Accordingly, stated interest on the Notes should be taxable to you as ordinary income when paid or accrued in accordance with your method of accounting for U.S. federal income tax purposes. Our position is not binding on the IRS. If the IRS takes a contrary position, you may be required to accrue OID from the time of issuance, as described below, regardless of your method of accounting for U.S. federal income tax purposes.

In the event we exercise our option to defer payments of interest, the Notes would be treated as retired and reissued for their issue price solely for purposes of the OID rules and you would be required to treat all stated interest on the deemed reissued Notes as OID. Consequently, during any period of interest deferral, and any period thereafter, you will include all stated interest in gross income as it accrues using a constant yield method before the receipt of cash. The calculation of the amount of such accruals may be complex, and therefore you should consult your tax adviser regarding the tax consequences if the Notes were treated as issued (or deemed reissued) with OID.

The amount of interest will include any amounts withheld in respect of Canadian taxes and, without duplication, any additional amounts paid with respect thereto. Interest on the Notes will be foreign-source income for foreign tax credit purposes.

Sale or Other Taxable Disposition of the Notes

Upon the sale or other taxable disposition of a Note, you will recognize taxable gain or loss equal to the difference between the amount realized on the sale or other taxable disposition (less any amount equal to accrued but unpaid interest, which will be taxable as interest income, as described above) and your tax basis in the Note. Assuming we do not defer interest payments on the Notes and the Notes are not treated as issued with OID, your tax basis in a Note will generally equal the cost of your Note. If the Notes are treated as issued (or deemed reissued) with OID, your tax basis in a Note will generally equal the cost of your Note, increased by any OID previously included in income, and decreased by payments received on the Note after the date of such issuance (or deemed reissuance). Any gain or loss will generally be U.S.-source income or loss for purposes of computing your foreign tax credit limitation.

Gain or loss realized on the sale or other taxable disposition of a Note will generally be capital gain or loss and will be long-term capital gain or loss if at the time of the sale or other taxable disposition the Note has been held for more than one year. Long-term capital gains recognized by non-corporate U.S. Holders are subject to reduced tax rates. The deductibility of capital losses is subject to limitations.

Automatic Conversion

The conversion of Notes for Conversion Preferred Shares pursuant to the Automatic Conversion should be treated as a tax-free recapitalization for U.S. federal income tax purposes. Thus, no income, gain or loss should be recognized on the conversion except to the extent that there is accrued but unpaid interest at the time of the conversion (which will be treated as such). Any Conversion Preferred Shares will be treated as first being received for the accrued but unpaid interest and the remainder will be treated as received upon conversion of the Notes. Your tax basis in the Conversion Preferred Shares received (other than any such shares received with respect to accrued interest) will equal the tax basis of the Notes that were converted. Your tax basis in the Conversion Preferred Shares received with respect to accrued interest will equal the fair market value of the shares received. Your holding period for the Conversion Preferred Shares received will include your holding period for the Notes converted, except that the holding period of any shares received with respect to accrued interest will commence on the day after the date of receipt.

Consequences if the Notes are Treated as Equity for U.S. Federal Income Tax Purposes

If the Notes are treated as equity for U.S. federal income tax purposes, the following U.S. federal income tax consequences should result. The discussion under this section generally assumes that we are not, and will not become, a passive foreign investment company, or a PFIC, as described below.

Payments of Interest

Payments of interest on the Notes will be treated as dividends to the extent paid out of our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. It is expected that payments of interest on the Notes generally will be taxed as dividends.

If you are a non-corporate U.S. Holder, certain dividends paid to you by "qualified foreign corporations" may be taxed at favorable rates. However, these favorable rates are available only if certain conditions are met, including a requirement that you hold the applicable security for a minimum period during which you are not protected from the risk of loss. The IRS has ruled that where a security treated as equity for U.S. federal income tax purposes provides for repayment of the principal amount at maturity, a holder's creditor rights with respect to the principal repayment may constitute protection from the risk of loss. Therefore, the minimum holding period requirement might not be met with respect to the Notes. If you are a non-corporate U.S. Holder, you should consult your tax adviser with respect to the "qualified dividend income" rules if the Notes are treated as equity for U.S. federal income tax purposes. Interest payments on the Notes will not be eligible for the dividends-received deduction generally available to U.S. corporations under the Code with respect to certain dividends.

The amount of dividend income will include any amounts withheld in respect of Canadian taxes and, without duplication, any additional amounts paid with respect thereto.

Interest on the Notes will be foreign-source income for foreign tax credit purposes. However, if, as described above, your creditor rights with respect to the principal repayment constitute protection from the risk of loss, you may not be able to meet the minimum holding period necessary to claim foreign tax credits in the case that any Canadian tax is withheld from interest payments.

Sale or Other Taxable Disposition of the Notes

Upon the sale or other taxable disposition of a Note, you will recognize taxable gain or loss equal to the difference between the amount realized on the sale or taxable disposition and your tax basis in the Note. Your tax basis in a Note will generally equal the cost of your Note. Gain or loss, if any, will generally be U.S.-source income or loss for purposes of computing your foreign tax credit limitation. Gain or loss realized on the sale or other taxable disposition of a Note will generally be capital gain or loss and will be long-term capital gain or loss if at the time of the sale or other taxable disposition the Note has been held for more than one year. Long-term capital gains recognized by non-corporate taxpayers are subject to reduced tax rates. The deductibility of capital losses is subject to limitations.

PFIC Rules

In general, a non-U.S. corporation will be considered a PFIC for any taxable year in which (1) 75% or more of its gross income is "passive income" under the PFIC rules or (2) 50% or more of the average quarterly value of its assets consists of assets that produce, or are held for the production of, "passive income." For this purpose, "passive income" generally includes interest, dividends, rents, royalties and certain gains (including gains from transactions in commodities). Exclusions are provided for certain gains from commodities earned in the active conduct of a business. For purposes of determining if a non-U.S. corporation is a PFIC, if the non-U.S. corporation directly or indirectly owns at least 25% by value of the shares of another corporation, it will be treated as if it holds directly its proportionate share of the assets and receives directly its proportionate share of the income of such other corporation. If a corporation is treated as a PFIC with respect to you for any taxable year, it generally will continue to be treated as a PFIC with respect to you in all succeeding taxable years, regardless of whether the corporation continues to meet the PFIC requirements in such years, unless certain elections are made.

We believe that we were not a PFIC for our 2015 taxable year and do not expect to be a PFIC for our 2016 taxable year. However, because the composition of our income and assets will vary over time and because there are uncertainties in the characterization of certain of our income and assets for PFIC purposes, there can be no assurance that we will not be a PFIC for any taxable year.

If we were a PFIC for any taxable year during which you owned the Notes, gain recognized by you on a sale or other disposition of the Notes would be allocated ratably over your holding period for the Notes. The amounts allocated to the taxable year of the sale or other disposition and to any year before we became a PFIC would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to tax at the highest rate in effect for individuals or corporations, as appropriate, for that taxable year, and an interest charge would be imposed on the resulting tax liability. Similar treatment may apply to certain excess distributions. Certain elections may be available that would result in alternative treatments (such as mark-to-market treatment) of the Notes. You should consult your tax adviser to determine whether any of these elections would be available and, if so, what the consequences of the alternative treatments would be in your particular circumstances.

If we were a PFIC for any taxable year during which you owned the Notes, you would generally be required to file annual returns containing such information as the IRS may require.

Conversion Preferred Shares

The discussion under this section generally assumes that we are not, and will not become, a PFIC, as described above.

Dividends

Distributions on the Conversion Preferred Shares will be treated as dividends to the extent paid out of our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. It is expected that distributions on the Conversion Preferred Shares generally will be taxed as dividends.

If you are a non-corporate U.S. Holder, certain dividends paid to you by "qualified foreign corporations" may be taxed at favorable rates. We expect that we will constitute a qualified foreign corporation for U.S. federal income tax purposes and that distributions on the Conversion Preferred Shares to non-corporate U.S. Holders that are treated as dividends for U.S. federal income tax purposes will be treated as qualified dividend income eligible for such reduced rates, provided the applicable holding period requirements are met. Distributions on the Conversion Preferred Shares will not be eligible for the dividends-received deduction generally available to U.S. corporations under the Code with respect to certain dividends.

The amount of dividend income will include any amounts withheld in respect of Canadian taxes.

Distributions that are treated as dividends for U.S. federal income tax purposes will be foreign-source income for foreign tax credit limitation purposes. As discussed above, withholding of Canadian tax is imposed at a 25% rate (reduced to 15% for recipients that are residents of the U.S. eligible for benefits under the Canada-United States Tax Convention) both on cash and non-cash distributions by us to persons that are not Canadian residents. Such Canadian tax withholding may exceed your allowable foreign tax credit for the taxable year of the distribution. To the extent a refund of the tax withheld is available to you under the laws of Canada or under the Canada-United States Tax Convention, the amount of tax withheld that is refundable will not be eligible for credit against your U.S. federal income tax liability, whether or not the refund is actually obtained. The foreign tax credit limitation rules are complex and dependent on the specific factual circumstances particular to you. Consequently, you should consult your tax adviser as to the U.S. federal income tax consequences relevant to you.

Dispositions

Upon a sale or other disposition of Conversion Preferred Shares, you generally will recognize gain or loss for U.S. federal income tax purposes equal to the difference between the amount realized and your tax basis in the Conversion Preferred Shares. Gain or loss will generally be capital gain or loss and will be long-term capital gain or loss if at the time of the sale or other taxable disposition the Conversion Preferred Shares have been held for more than one year (including the holding period for the Notes, as applicable). Long-term capital gains recognized by non-corporate taxpayers are subject to reduced tax rates. The deductibility of capital losses is subject to limitations. Gain recognized by you from a sale or other disposition of Conversion Preferred Shares will generally be treated as income from U.S. sources for foreign tax credit limitation purposes.

Backup Withholding and Information Reporting

Information returns may be required to be filed with the IRS in connection with payments on the Notes and proceeds received from a sale or other disposition of the Notes and dividends received with respect to the Conversion Preferred Shares and proceeds from the disposition of those shares, unless you are an exempt recipient. You may also be subject to backup withholding on these payments in respect of your Notes or Conversion Preferred Shares unless you provide your taxpayer identification number and otherwise comply with applicable requirements of the backup withholding rules or you provide proof of an applicable exemption. Amounts withheld under the backup withholding rules are not additional taxes and may be refunded or credited against your U.S. federal income tax liability, provided the required information is timely furnished to the IRS.

You may be required to report information relating to an interest in the Notes or Conversion Preferred Shares or an account through which the Notes or Conversion Preferred Shares are held, subject to certain exceptions (including an exception for Notes or Conversion Preferred Shares held in accounts maintained by certain U.S. financial institutions), by attaching a complete IRS Form 8938 to your tax return for each year in which you hold an interest in the Notes or Conversion Preferred Shares. You should consult your tax adviser regarding information reporting requirements relating to your ownership of the Notes or Conversion Preferred Shares.

PLAN OF DISTRIBUTION

Emera may sell Notes to or through underwriters purchasing as principal and may also sell Notes to one or more purchasers directly or through agents. Any underwriting syndicate in respect of an offering of Notes will be led by J.P. Morgan Securities LLC. Notes may be sold from time to time in one or more transactions at a fixed price or prices. If, in connection with the offering of Notes at a fixed price or prices, the underwriters have made a bona fide effort to sell all of the Notes at the initial offering price fixed in the applicable Prospectus Supplement, the public offering price may be decreased and thereafter further changed, from time to time, to an amount not greater than the initial public offering price fixed in the Prospectus Supplement in which case the compensation realized by the underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Notes is less than the gross proceeds paid by the underwriters to Emera.

Any additional underwriter or agent engaged in connection with the offering and sale of a particular series or issue of Notes will be identified in a Prospectus Supplement along with the terms of the offering, including the public offering price, the proceeds to Emera and any fees, discounts or other compensation payable to the underwriters or agents.

Under agreements which may be entered into by Emera, underwriters and agents who participate in the distribution of Notes may be entitled to indemnification by Emera against certain liabilities, including liabilities arising out of any misrepresentation in this Prospectus and the documents incorporated by reference therein, other than liabilities arising out of any misrepresentation made by underwriters or agents who participate in the offering of Notes.

There is no market through which any Notes offered hereunder may be sold. Accordingly, purchasers may not be able to resell the Notes purchased under this Prospectus. This may affect the pricing of the Notes in the secondary market, the transparency and availability of trading prices, the liquidity of the Notes, and the extent of issuer regulation. In connection with any offering of Notes, the underwriters or agents may, subject to the foregoing, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. Any underwriters or agents to or through whom Notes are sold by Emera for public offering and sale may make a market in the Notes, but such underwriters or agents will not be obligated to do so and may discontinue any market making at any time without notice.

This Prospectus qualifies the Notes and the First Preferred Shares into which they are convertible for distribution under the Securities Act (Nova Scotia) in connection with sales of the Notes to purchasers in the United States and elsewhere outside Canada. This Prospectus does not qualify the distribution of any securities sold to purchasers in the Province of Nova Scotia or in any other province or territory of Canada.

EARNINGS COVERAGE RATIOS

The applicable Prospectus Supplement will provide the earnings coverage ratios with respect to the issuance of Notes pursuant to such Prospectus Supplement.

LEGAL MATTERS

Certain legal matters relating to the any offering of Notes will be passed upon on behalf of the Company by Stephen D. Aftanas, Corporate Secretary of Emera, by Davis Polk & Wardwell LLP, New York, New York, and by Osler, Hoskin & Harcourt LLP, Toronto, Ontario.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRMS

Ernst & Young LLP, Chartered Professional Accountants, Halifax, Nova Scotia, are the auditors of Emera. Ernst & Young LLP report that they are independent of Emera in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Nova Scotia.

The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) incorporated in this Prospectus by reference to TECO Energy's Annual Report on Form 10-K for the year ended December 31, 2015 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, given on the authority of said firm as experts in auditing and accounting.

INTERESTS OF EXPERTS

As at the date of this Prospectus, the partners and associates of Osler, Hoskin & Harcourt LLP, as a group, beneficially own, directly or indirectly, less than 1% of any class of securities of Emera.

TRANSFER AGENT, REGISTRAR, PAYING AGENT AND INDENTURE TRUSTEE

CST Trust Company will be appointed as Canadian trustee, Canadian registrar, Canadian paying agent and Canadian transfer agent in respect of the Notes and American Stock Transfer & Trust Company, LLC will be appointed as U.S. trustee, U.S. registrar, U.S. paying agent and U.S. transfer agent in respect of the Notes. The Notes will be issued in book-entry only form through the Clearing Agency. See "Description of the Notes—Book-Entry Only Form".

ENFORCEMENT OF CIVIL LIABILITIES

Emera is incorporated in Nova Scotia. Some of the directors and officers of Emera, and some of the experts named in this Prospectus, are residents of Canada or otherwise reside outside the U.S., and all or a substantial portion of their assets, and a substantial portion of the assets of Emera, are located outside the U.S. Emera has appointed an agent for service of process in the U.S., but it may be difficult for holders of the Notes who reside in the U.S. to effect service within the U.S. upon those directors, officers and experts who are not residents of the U.S. It may also be difficult for holders of the Notes who reside in the U.S. to realize in the U.S. upon judgments of courts of the U.S. predicated upon the civil liability of Emera and the civil liability of the directors and officers of Emera and experts under U.S. federal securities laws.

Emera has been advised by its Canadian counsel, Osler, Hoskin & Harcourt LLP, that a judgment of a U.S. court predicated solely upon civil liability under U.S. federal securities laws would probably be enforceable in Canada if the U.S. court in which the judgment was obtained has a basis for jurisdiction in the matter that would be recognized by a Canadian court for the same purposes. Emera has also been advised by Osler, Hoskin & Harcourt LLP, however, that there is real doubt whether an action could be brought in Canada in the first instance on the basis of liability predicated solely upon U.S. federal securities laws.

J. Wayne Leonard and Richard P. Sergel, two of the Company's directors, reside outside of Canada and have appointed Emera Incorporated, 5151 Terminal Road, Halifax, Nova Scotia B3J 1A1 as agent for service of process. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person that resides outside of Canada, even if such person has appointed an agent for service of process.

Emera filed with the SEC, concurrently with its registration statement on Form F-10, an appointment of agent for service of process on Form F-X. Under the Form F-X, Emera appointed Emera US Finance LP as its agent for service of process in the U.S. in connection with any investigation or administrative proceeding conducted by the SEC, and any civil suit or action brought against or involving Emera in a U.S. court arising out of or related to or concerning an offering of securities under this Prospectus.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages where the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal adviser.

CERTIFICATE OF EMERA INCORPORATED

Dated: June 8, 2016

This short form base shelf prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of the province of Nova Scotia.

(signed) *Christopher Huskilson*
President and
Chief Executive Officer

(signed) *Greg W. Blunden*
Chief Financial Officer

On behalf of the Board of Directors:

(signed) *M. Jacqueline Sheppard*
Director

(signed) *Richard P. Sergel*
Director

Emera