2016 Annual Report

Emera

Emera Inc. is a geographically diverse energy and services company headquartered in Halifax, Nova Scotia with approximately $29 billion in assets and 2016 revenues of more than $4 billion. The company invests in electricity generation, transmission and distribution, gas transmission and distribution, and utility energy services with a strategic focus on transformation from high carbon to low carbon energy sources. Emera has investments throughout North America, and in four Caribbean countries. Emera continues to target having 75–85% of its adjusted earnings come from rate-regulated businesses.

Emera's common and preferred shares are listed on the Toronto Stock Exchange and trade respectively under the symbol EMA, EMA.PR.A, EMA.PR.B, EMA.PR.C, EMA.PR.E, and EMA.PR.F. Depositary receipts representing common shares of Emera are listed on the Barbados Stock Exchange under the symbol EMABDR. Additional information can be accessed at www.emera.com or at www.sedar.com.

TABLE OF CONTENTS

Letter to Shareholders 1
Management's Discussion and Analysis 6
- Emera Consolidated 15
- Emera Florida and New Mexico 35
- NSPI 45
- Emera Maine 54
- Emera Caribbean 59
- Emera Energy 67
- Corporate and Other 75

Management Report 106
Independent Auditors' Report 107
Consolidated Financial Statements 108
Notes to the Consolidated Financial Statements 116
Emera Leadership and Board 199
Shareholder Information 200

On the front cover:

Nova Scotia Power's Digby Neck Wind Farm, Digby, Nova Scotia (at left);

New Mexico Gas Company's Highway 599 Border Station, Santa Fe, New Mexico (top right);

Tampa Electric's Polk Power Plant, Polk County, Florida (centre);

Barbados Light & Power's Solar Photovoltaic Generation Plant, Trents, St. Lucy, Barbados (bottom right).

Letter to Shareholders

Dear Fellow Shareholder:

2016 was a significant and transformative year for Emera.

On July 1, with the closing of the transaction with TECO Energy, Emera became one of the 20 largest North American publicly traded utilities and in August we became a member of the S&P TSX60 index. These were major achievements by the team just ten months after announcing the deal which was valued at more than US$10 billion.

The TECO Energy transaction is accretive to our business by almost every measure – earnings, cash, scale, liquidity and capacity. The first two full quarters of combined operations demonstrated Emera's increased earnings power.

With 7,400 talented employees – including our newest team members from Tampa Electric, TECO Services, Peoples Gas and New Mexico Gas – we now serve 2.5 million customers in the United States, Canada and the Caribbean.

We enhanced our percentage of regulated earnings and our earnings diversity. We added new platforms for organic growth with the addition of the higher growth Florida and New Mexico markets, creating new opportunities to transition from high to low carbon in the markets we serve. Adding the natural gas Local Distribution (LDC) utility segment also creates new opportunities and diversity for Emera. Throughout, we advanced our major projects including the Maritime Link, Polk 2 gas combined cycle, Rio Puerco gas transmission and the St. Lucy and Big Bend solar projects.

Today Emera has total assets of more than $29 billion, compared to $12 billion just a year ago and $4 billion 10 years ago.

Jackie Sheppard
Chair, Emera Inc.
Board of Directors

Christopher Huskilson
President and
Chief Executive Officer

A year of achievements

In 2016, we demonstrated the strength of our existing businesses and enhanced our financial performance. Our strong financial performance is a continuation of the longer-term trend of delivering consistent solid performance for our shareholders.

Since 2010, we have increased adjusted earnings per share at an 8.5 per cent compound annual growth rate and grown the dividend at an 8.8 per cent rate over the same period. Supporting the growing dividend is our 16.6 per cent growth in operating cash flow since 2010. Demonstrating our disciplined approach to delivering value to our shareholders, we target generating 75 – 85 per cent of earnings from our regulated operations and we have a dividend payout ratio target of 70 – 75 per cent, so we more than cover our dividend with stable, predictable regulated earnings.

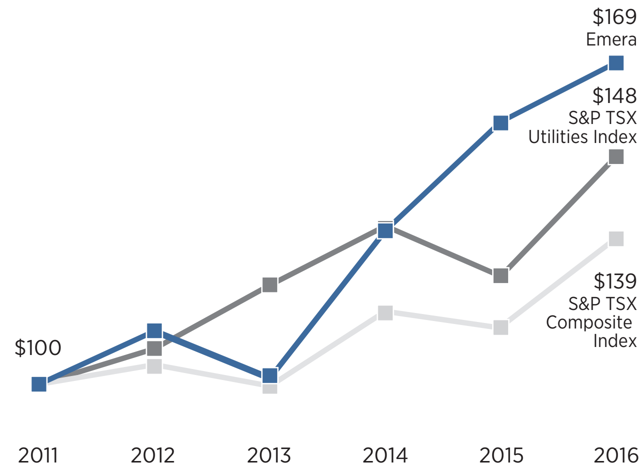
In 2016, adjusted earnings per share grew almost 23 per cent, to $2.77 per share from $2.26 the prior year, and operating cash flow grew 45 per cent to $1.05 billion. These strong results were driven by the performance of our regulated utilities and the addition of Emera Florida and New Mexico. Consistent with our earnings growth, actual cash dividends paid increased 20 per cent and we extended our 8 per cent compound annual dividend growth target through to 2020.

Consistent Dividend Growth:
In July, we increased our annual common share dividend by 10 per cent to $2.09, and extended the 8 per cent annual dividend growth target through to 2020. Since 2010, Emera has increased its dividend at a compound annual growth rate of almost 9 per cent.

Industry Leading Longer-term Total Shareholder Return (TSR):
Realizing robust and long term total shareholder return is an important gauge for our performance. Over the last ten years Emera has delivered consistent TSR totaling 208 per cent. That means $100 invested at the beginning of 2007 is now worth $308. Over the last five years, Emera has delivered an annualized TSR of 11 per cent compared to 8.2 per cent delivered by S&P TSX Capped Utilities Index and 5.5 per cent delivered by TSX Composite. As the graph on the right indicates, $100 invested in Emera on December 31, 2011 was worth $169 on December 31, 2016, compared to $131 in the S&P TSX Capped Utilities Index and $149 in the S&P TSX Composite Index.

Cumulative Total Return on $100 Investment

December 31, 2011 to December 31, 2016



Step Change in Cash Flow:
Strengthening our operating cash flow continues to be an important goal, supporting our growing dividend and our capital investment plans. In 2016, driven by the addition of the Florida and New Mexico operations, Emera realized an increase in cash flow from operations, which grew to $1.05 billion compared to $726 million in 2015.

Since refinancing the Bear Swamp facility in late 2015, we have raised over $1 billion cash through various strategic actions, including the sale of Emera's shares in Algonquin Power & Utilities Corp. (APUC) and an approved reduction in Barbados Light and Power's contingency funding for its self-insurance fund (SIF).

These transactions, particularly the APUC investment and the subsequent share sale, are also evidence of Emera's approach to continually evaluate, optimize and re-deploy capital to extract the highest value.

Success in Capital Markets:
Starting with the 2015 announcement of the TECO Energy transaction and throughout 2016, Emera was very active in the capital markets. During this period, we issued US hybrid securities and debt, Canadian debt and convertible debentures for the TECO Energy transaction. The US debt issuance was one of the largest utility financing deals ever in the United States. We also raised $345 million by issuing common equity late last year, and raised more than $100 million through our dividend reinvestment program. These successful financing initiatives reflect the market's continued confidence in Emera.

Strength of our regulated portfolio

With our Florida and New Mexico businesses integrated, more than 90 per cent of Emera's earnings now come from our regulated businesses, surpassing our target of 75 – 85 per cent.

Tampa Electric recently completed upgrading Polk Power Station, expanding capacity by about 460 MW.

In Florida, strong customer growth allows our businesses to provide excellent rate base growth that creates affordable energy for customers with the second lowest rates among investor owned utilities in the state. We also see opportunities to drive incremental growth through Emera's strategy centered on greater concentrations of clean, affordable energy.

At Tampa Electric, customers are actually paying less in 2017 due to lower fuel costs, which more than offset the $110 million base rate increase due to the completion of the $700 million investment in Polk Unit 2 in January 2017.

Nova Scotia Power implemented a plan to provide stable and predictable rates for customers through to the end of 2019. Its Rate Stabilization Plan was approved by the regulator.

Emera Maine and the Caribbean provided stable and predictable earnings, as they rolled out initiatives for continuous improvements to customer experience.

Strategic role of our unregulated business

Over the years, Emera Energy has performed a significant role in developing new capabilities and relationships in strategic markets. In addition to the earnings contribution, particularly during periods of extreme weather and volatile market conditions, Emera Energy continues to provide strategic links that integrate our overall business. With its portfolio of power plants and a marketing business serving customers throughout northeastern North America, we collectively gain from its many important relationships and market knowledge.

From a purely earnings point of view, Emera Energy does better under extreme weather conditions, when natural gas prices are high and when there is price volatility in the market. While not taking commodity risk, these conditions allow it to earn more in some years compared to others. In 2016, in spite of power prices in New England being well below 2015 levels, Emera Energy delivered adjusted net income of $24 million which is in the middle of the range of expectations for a mild weather year.

Significant progress on major initiatives

The Maritime Link project remains on schedule and on budget with an expected in-service date in late 2017. When completed, it will create new energy links throughout the region. This project speaks to our approach to creating transformative solutions that benefit an entire region while delivering value to customers and value to our investors.

Early in 2017, Tampa Electric completed the Polk Power Station Unit 2 conversion into a state of the art combined cycle unit. The expansion added approximately 460 MW of generating capacity while increasing the efficiency of the existing units by 37 per cent. Since then, Tampa Electric has also completed construction of its 23 MW Big Bend solar array, the most advanced solar project in the region.

The 23 MW Big Bend Solar facility is the largest solar array in the Tampa Bay area.

In the Caribbean, we completed the 10 MW St. Lucy Solar Farm, an important step towards our vision for 100 per cent renewable electrification of Barbados by 2045. The plant became operational in September. Consistent with our integrated approach on renewables, it will facilitate future energy storage and electric vehicle penetration on the island.

Cape Sharp Tidal, our joint venture with OpenHydro, installed its first 2 MW turbine in the Bay of Fundy and has been supplying energy to the grid since late last year. Later this year, we plan to deploy a second 2 MW turbine. Emera is excited to lead the way in building a tidal industry, generating economic growth and investing in energy innovation for the region.

Enabling innovation and investing in our communities

As we grow, so does our capacity to support economic growth, enable innovation and build capacity in the communities we serve. We're invested in our communities by making sustainable energy affordable and by supporting the causes that matter to our people and our customers.

Our initiatives include partnerships with academic institutions to spur innovation, grants to generate economic development, funding for home heating retrofits for low income citizens, an annual United Way campaign and numerous employee giving initiatives. We believe that when our communities grow and prosper, our business will as well.

In 2017, we will launch Emera's first sustainability report, highlighting our commitment to stakeholders and providing an integrated view of our shared values.

Emera is proud to be a partner in initiatives that spark innovation, like the Discovery Centre in Halifax.

Moving forward with momentum

Emera has a promising future with significant strategic initiatives already on the horizon. Our capital spending projection for 2017 through 2020 is $6.5 billion of visible, identified investments.

Emera's strategy centered on clean, affordable energy will continue to drive growth.

At Tampa Electric, planning is underway to develop large scale solar power and to reduce the carbon intensity of generation through increased use of natural gas.

At Peoples Gas and New Mexico Gas, we see potential to expand distribution of cleaner burning natural gas to vehicle fleets, industrial customers and new residential customers.

Cape Sharp Tidal is Canada's first in-stream tidal energy turbine to provide tidal energy to the grid. A second turbine deployment is planned for 2017.

Massachusetts made a major commitment to clean energy in order to meet legislated, state-level emissions reduction and renewable energy targets. Legislation signed into law last summer requires a competitive solicitation process for long-term contracts to supply the state with 9.45 TWh of renewable energy options.

Our Atlantic Link project – a proposed HVdc transmission line that could deliver 900 MW of clean energy from northern Maine and Atlantic Canada directly to southern Massachusetts – has the potential to provide long-term access to renewable energy at stable prices for the Commonwealth of Massachusetts (and the New England electricity system). Our proposal offers a compelling option to move clean energy into New England with the ability to collect and deliver energy from a number of diverse sources. We have initiated a solicitation process for energy to supply our proposed transmission line.

Other incremental investment opportunities supporting our capital plan include Nova Scotia Power's hydro refurbishment and transmission and distribution system upgrades, Barbados' renewable energy initiatives and Emera Maine's transmission system improvements.

Barbados Light & Power is helping drive the transformation of Barbados to a 100% clean-energy economy, including solutions like electric vehicles.

Leading the way in corporate governance

Strong and effective corporate governance is a priority at Emera. Both our Board and management teams believe that strong governance standards enable better business decision making and execution. Guidance from our Board has been critical to our success to date. The Board's rigorous oversight of both the strategy development process and the strategy itself is vital to the future growth of our business.

The quality of Emera's corporate governance was recognized in *The Globe and Mail's* Board Games 2016 ranking, when Emera placed first among 231 companies and trusts in the S&P/TSX composite index.

As one of our first integration steps, Emera adopted a new Code of Conduct in 2016, replacing Emera's Standards for Business Conduct and TECO Energy's Code of Ethics & Business Conduct. The new Code ensures that all of our employees in all parts of our business and geographies are guided by a common Code based on our shared responsibility, purpose and values.

The Board also established the Health, Safety and Environment Committee (HSEC) as a standing committee of the Board of Directors. Recognizing the new size and scale of our business, the HSEC was created to assist the Board in carrying out its oversight and coordination responsibilities in relation to Emera's health, safety and environmental programs.

In 2016, 97 per cent of shareholders given the opportunity to have a "Say on Pay" voted in favour of Emera's approach to executive compensation. We are pleased to offer shareholders a "Say on Pay" resolution at the Company's 2017 annual meeting. Shareholders' views are considered very seriously by the Board and management, and this opportunity for feedback on executive compensation is particularly important.

As we strive continuously for improvement, the Board annually assesses its performance and that of the Chair, individual Directors and the Board Committees to find ways to enhance overall effectiveness. The major areas of focus that emerged from the 2016 Board and Director Performance Assessment included corporate strategy, management succession and leadership development, Board processes and longer-term succession planning.

Strategy is a top priority for the Board. Directors expressed satisfaction with the alignment between the Board and management on strategy. The Board continues to believe that with our dynamic and ever changing world, strategy review and development is central to Emera's future success.

Board members recognize the strength of the senior leadership team at Emera and the ongoing formal process of leadership identification and development under the oversight of the Management Resources and Compensation Committee.

With the TECO Energy transaction, Emera has undergone significant change. Recognizing this, the Board will step up its focus on long term Board succession planning in 2017. We will develop an action plan based on the findings from this assessment and progress on the action plan will be reported to the Board throughout 2017.

In 2016, Board renewal principles intended to promote orderly succession and balanced renewal of membership on the Board were adopted. Under these principles, the overall needs of the Board given Emera's new scale, complexity and geographies will be considered. In addition, consideration will be given to the age and tenure of Directors.

We were pleased to welcome John Ramil, past president and CEO of TECO Energy, to the Emera Board in September 2016. A Tampa native, John is a respected energy leader with an impressive 40-year career with TECO Energy. We also want to thank Wayne Leonard who, on account of health issues, retired from the Board of Directors, effective January 1, 2017. Wayne's considerable experience in regulated and non-regulated utilities and capital markets made him a valuable member of the Board. We wish Wayne the best and are grateful for all his contributions.

We want to take this opportunity to thank our fellow Board members for their ongoing commitment. The Board's collective strength in experience and judgement was critical to Emera's success in 2016.

Emera's success is thanks to the hard work of our employees in Canada, the USA and the Caribbean.

Our people drive our success

The progress and momentum we saw in 2016 is possible because of the commitment of our employees. We see renewed energy across the business as our company continues to grow. We are happy to welcome all of the employees who joined Emera when the TECO Energy transaction closed, and we look forward to continue our growth in 2017.

What sets the Emera team apart is a culture that shares a common purpose to safely provide services that are affordable, reliable and sustainable to our customers. We thank each and every Emera employee for their hard work and unwavering focus throughout the year.

We look forward to an even brighter future – and the opportunity to continue to earn your support.

Sincerely,

Jackie Sheppard
Chair,
Emera Inc. Board of Directors

Chris Huskilson
President and CEO

Management's Discussion & Analysis

As at February 10, 2017

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments ("Emera") during the fourth quarter of 2016 relative to the same quarter in 2015; the full year of 2016 relative to 2015 and 2014; and its financial position as at December 31, 2016 relative to December 31, 2015. 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. The Company's activities are carried out through six business segments: Emera Florida and New Mexico, Nova Scotia Power Inc. ("NSPI"), Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2016. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

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

Emera Rate-Regulated Subsidiary or Equity Investment	Accounting Policies Approved/Examined By
Subsidiary	
Tampa Electric – Electric Division of Tampa Electric Company ("TEC")	Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC")
Peoples Gas System ("PGS") – Gas Division of TEC	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Emera Maine	Maine Public Utilities Commission ("MPUC") and FERC
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Dominica Electricity Services Ltd. ("Domlec")	Independent Regulatory Commission, Dominica ("IRC")
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	National Energy Board ("NEB")
Equity Investment	
NSP Maritime Link Inc. ("NSPML")	UARB
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline LLC ("M&NP")	NEB and FERC
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities
St. Lucia Electricity Services Limited ("Lucelec")	National Utility Regulatory Commission ("NURC")

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

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

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations are discussed in the Outlook section of the MD&A and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; enterprise resource planning implementation risk; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; project development and construction risk; derivative financial instruments and hedging; 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.

INTRODUCTION AND STRATEGIC OVERVIEW

Emera Incorporated is a geographically diverse energy and services company, targeting eight per cent annual dividend growth through 2020. The Company invests in electricity generation, electricity transmission and distribution, gas transmission and distribution, and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States and the Caribbean. Emera seeks to deliver long-term growth to investors and, accordingly, the primary measures of performance are annual dividend growth, earnings per common share growth, adjusted earnings per common share growth and total shareholder return. Below are Emera's one, three and five year performance for these metrics:

For the	Year ended December 31, 2016		
	1 year	3 year	5 year
Dividend per share compound annual growth rate	19.9%	12.2%	8.7%
Earnings per share compound annual growth rate	(51.1%)	(6.7%)	(7.7%)
Adjusted earnings per share compound annual growth rate (see Non-GAAP Financial Measures below)	22.6%	12.2%	6.7%
Emera annualized total shareholder return (1)	9.6%	18.3%	10.0%
S&P/TSX Capped Utilities Index annualized total shareholder return (2)	17.4%	9.3%	4.9%

(1) 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.
(2) 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 per cent. 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.

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. In Florida and New Mexico the Company is evaluating a number of initiatives, including transmission and solar generation, that would reduce carbon emissions. NSPI has invested in wind energy, biomass and hydroelectricity and is on track to meet a minimum 40 per cent renewable standard by 2020. In the Caribbean, Emera is similarly focused on introducing cleaner generation alternatives, with an emphasis on affordability and fuel cost stability for its customers.

Emera is investing in electricity transmission to 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 benefit from enhanced connection to the northeastern United States, providing potential for excess renewable energy to be delivered throughout that region.

Since its formation in 2003, Emera Energy has become an active participant in the northeastern United States electricity and natural gas markets. It has built a strong marketing, trading and asset management business, based on comprehensive market knowledge, focus on customer service and robust risk management. The integration and performance of three New England Gas Generating Facilities ("NEGG") 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, lower-cost natural gas, growing demand for new electric heating and cooling solutions, the requirement for large-scale transmission projects to deliver new energy sources to customers, and environmental concerns. These environmental concerns include a desire to reduce the emissions of carbon dioxide and other greenhouse gases and the potential effect of climate change, including changes in global and regional weather patterns, changes in the frequency and intensity of extreme weather events, and rising sea levels. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving replacement of higher-carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver that energy to market.

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

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

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

Emera targets achieving 75 to 85 per cent of its adjusted net income (a non-GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable earnings and cash flows that fund dividends, reinvestment and are reflective of the Company's risk tolerance. The Company is expected to achieve this adjusted net income target with the July 1, 2016 close of its acquisition of TECO Energy, Inc. ("TECO Energy"). The Company targets a dividend payout ratio of 70 to 75 per cent of adjusted net income.

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

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments and foreign currency exchange 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.

BUSINESS OVERVIEW

Energy markets across North America are affected by a number of trends that shape the environment in which energy and utility companies operate. 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. Advocacy for cleaner, renewable sources of electricity has become a defining trend in the industry globally, not just in the markets Emera serves. 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 despite any cost differential with more carbon-intensive generating options.

The transformation in generation and fuel selection also has a significant impact on the requirement for new transmission infrastructure. In addition to the traditional issues of infrastructure life expectancy and changing technology, infrastructure renewal planning must now also consider 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 new infrastructure will need to be addressed in the context of the intense focus of customers and regulators on electricity pricing and affordability. Going forward, the ability of energy companies to achieve their growth objectives, environmental targets and other goals, will depend on their ability to address price and affordability.

As technology advances, so does 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. Load is the total amount of electricity or gas delivered in order to meet energy-consumption demands of Emera's customers. In addition, as with wind turbine technology, advancements in solar technology have significantly reduced solar generation costs, 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 and will facilitate the integration of more distributed generation.

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.

NON-GAAP FINANCIAL MEASURES

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

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

Adjusted Net Income

Emera calculates an adjusted net income measure by consistently excluding the effect of:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp;
- the amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline; and
- the mark-to-market adjustments included in Emera's other income related to the effect of TECO Energy acquisition USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures") for the TECO Energy acquisition.

Management believes excluding from income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows and the ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors use this non-GAAP measure for evaluation of performance and incentive compensation.

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

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

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Net income attributable to common shareholders	**$ 70**	$ 192	**$ 227**	$ 397	$ 407
After-tax mark-to-market gain (loss)	**$ (34)**	$ 105	**$ (248)**	$ 67	$ 88
Adjusted net income attributable to common shareholders	**$ 104**	$ 87	**$ 475**	$ 330	$ 319
Earnings per common share – basic	**$ 0.34**	$ 1.31	**$ 1.33**	$ 2.72	$ 2.84
Adjusted earnings per common share – basic	**$ 0.51**	$ 0.59	**$ 2.77**	$ 2.26	$ 2.23

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-GAAP financial measure used by Emera. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, make capital expenditures and finance working capital requirements.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to adjusted net income calculations described above, this measure represents EBITDA absent the income effect of Emera's mark-to-market adjustments, as previously discussed.

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies, but in management's view it appropriately reflects Emera's specific financial condition. These measures are not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance. EBITDA and Adjusted EBITDA are discussed further in the Consolidated Financial Review, Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy, and Corporate and Other sections.

EBITDA and Adjusted EBITDA Reconciliation

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Net income [1]	**$ 71**	$ 199	**$ 266**	$ 452	$ 453
Interest expense, net	**169**	70	**585**	212	180
Income tax expense (recovery)	**(6)**	21	**(22)**	93	113
Depreciation and amortization	**212**	88	**588**	340	329
EBITDA	**446**	378	**1,417**	1,097	1,075
Mark-to-market gain (loss), excluding income tax and interest	**(52)**	119	**(327)**	66	129
Adjusted EBITDA	**$ 498**	$ 259	**$ 1,744**	$ 1,031	$ 946

(1) Net income (loss) is income before Non-controlling interest in subsidiaries and Preferred stock dividends.

Electric Margin and Gas Margin

"Electric margin" and "Gas margin" are non-GAAP financial measure used to show the amounts that Emera's regulated utilities retain to recover non-fuel and non-clause related costs. Prudently incurred fuel costs are recovered from customers, except at Domlec, where substantially all prudently incurred fuel costs are passed to customers through the fuel pass-through mechanism. In addition, prudently incurred clause related costs and returns are recovered from customers. Management believes measuring electric and gas margin shows the portion of these utilities' revenues that directly contribute to Emera's income as distinguished from the portion of revenues that are managed through fuel adjustment and other clause mechanisms, which have a minimal impact on income.

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

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

SIGNIFICANT ITEMS AFFECTING EARNINGS

2016

Acquisition Related Costs

Emera incurred after-tax costs related to its acquisition of TECO Energy ("the Acquisition"), including legal, banking and advisory, stipulation commitments, accelerated vesting of TECO Energy stock-based compensation, pre-closing financing, beneficial conversion feature discount noted below and foreign exchange costs totalling a $13 million benefit in Q4 2016 ($0.06 benefit per common share) and $166 million expense for the year ended December 31, 2016 ($0.97 per common share). Emera incurred after-tax costs of $30 million in Q4 2015 ($0.21 per common share) related to its then-pending acquisition of TECO Energy, including legal, advisory, and financing costs. For the year ended December 31, 2015, TECO Energy acquisition related costs were $53 million after-tax ($0.36 per common share). All acquisition costs have been recognized in the Corporate and Other segment.

Included below in "After-Tax Mark-to-Market-Losses", are the foreign currency earnings effect related to the Convertible Debentures USD cash balance and the associated forward contracts. These resulted in a mark-to-market after-tax loss of $114 million in 2016 recorded in "Other income (expenses), net (a mark-to-market after-tax gain of $98 million in 2015).

In Q3 2016 substantially all of Emera's Convertible Debentures were converted to equity and, as a result, Emera recognized the difference between Emera's closing share price on the issuance date of the Convertible Debentures and their exercise price (the "Beneficial Conversion Feature discount") resulting in a cost of $62 million ($43 million after-tax or $0.24 per common share). This cost is included in the acquisition expense noted above.

After-Tax Mark-to-Market Losses

After-tax mark-to-market losses increased $139 million to a $34 million loss in Q4 2016 ($0.17 per common share) compared to $105 million gain in Q4 2015 ($0.71 per common share). Year-to-date losses increased $315 million to $248 million in 2016 ($1.45 per common share) compared to $67 million gain for the same period in 2015 ($0.46 per common share). The increased mark-to-market losses in the quarter and in the year ended December 31, 2016 relate to the effect of the Debenture Offering USD-denominated currency revaluation and forward contracts put in place to hedge the proceeds from the final instalment of the Debenture Offering. In addition, losses have increased due to changes in existing positions on Asset Management Agreements ("AMA") and long-term natural gas contracts at Emera Energy.

At inception of an AMA contract, the unrealized mark-to-market adjustment on the commodity portion of the contract is offset fully by the value of a corresponding gas transportation asset. Subsequent changes in gas prices result in unrealized mark-to-market gains or losses recorded in earnings. The corresponding transportation assets are amortized evenly over the contract term. The difference between these items results in unrealized mark-to-market gains or losses in earnings but ultimately the mark-to-market adjustments and transportation assets reduce to zero at the end of the contract term.

Investment in APUC

On December 8, 2016, Emera completed the sale of 12.9 million common shares of Algonquin Power and Utilities Corp. ("APUC"), representing approximately 4.7 per cent of APUC's issued and outstanding common shares for gross proceeds of $142 million. This sale resulted in a pre-tax loss of $12 million or $0.07 per common share (after-tax loss of $10 million or $0.06 per common share), which was recorded in "Other income (expenses), net" in Q4 2016. Emera no longer holds any interest in APUC.

On June 30, 2016, Emera exchanged 12.9 million APUC subscription receipts and dividend equivalents into 12.9 million APUC common shares. This conversion resulted in a pre-tax gain of $63 million or $0.42 per common share (after-tax gain of $53 million or $0.35 per common share), which was recorded in "Other income (expenses), net" in Q2 2016.

On May 24, 2016, Emera completed the sale of 50.1 million common shares of APUC, representing approximately 19.3 per cent of APUC's issued and outstanding common shares for gross proceeds of $544 million. This sale resulted in a pre-tax gain of $172 million or $1.15 per common share (after-tax gain of $146 million or $0.97 per common share), which was recorded in "Other income (expenses), net" in Q2 2016.

Gain on BLPC Self-Insurance Fund Regulatory Liability

BLPC maintains a Self-Insurance Fund ("SIF") for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. Third-party risk advisors were engaged to support a detailed risk analysis, which was completed to quantify the prudent assessment of the risk to BLPC's transmission and distribution system from natural catastrophes.

In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $29 million ($22 million USD). As a result, Emera recorded a pre-tax gain of $53 million ($41 million USD) or $0.35 per common share and an after-tax gain of $43 million ($34 million USD) or $0.29 per common share in "Other income (expenses), net". In Q3 2016, Emera received a distribution of $65 million ($50 million USD) from the fund.

Emera Energy Recognition of State Fuel Taxes

Emera Energy recorded a $20 million pre-tax or $0.13 per common share ($12 million after-tax or $0.08 per common share) liability for state tax on natural gas sales made from November 2013 through March 2016. This included $4 million pre-tax ($2 million after-tax) related to Q1 2016. The recognition of this liability resulted in an increase to "Non-regulated fuel for generation and purchased power" in Q2 2016.

2015

After-Tax Mark-to-Market Gains

After-tax mark-to-market gains increased $32 million to $105 million in Q4 2015 compared to $73 million in Q4 2014; and decreased $20 million to $67 million for the year ended December 31, 2015 compared to $88 million in 2014. The increased mark-to-market gains in the quarter were primarily due to the effect of USD-denominated currency and forward contracts related to the then-pending TECO Energy acquisition. The increase was 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 was primarily responsible for the year-over-year decrease in after-tax mark-to-market gains.

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 gain of $11 million (after-tax earnings of $9 million or $0.06 per common share) in "Income from Equity Investments". The gain was a result of APUC's share issuance price being higher than Emera's pre-issuance average book value.

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

BLPC recorded severance costs of $8 million ($6 million USD) relating to corporate restructuring, which was recorded in Operating, maintenance and general ("OM&G") in Q2 2015. The after-tax effect on Emera's Consolidated Net Income in Q2 2015, at Emera's then 80.7 per cent ownership of ECI, was $5 million ($0.04 per common share).

Sale of Northeast Wind Partnership II, LLC ("NWP") Equity Investment

On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for $282 million ($223 million USD). This sale resulted in a pre-tax gain of $19 million or $0.13 per common share (after-tax gain of $12 million or $0.08 per common share), which was recorded in "Other income (expenses), net" in Q1 2015.

CONSOLIDATED FINANCIAL REVIEW

Below is a table highlighting significant changes between adjusted net income from 2015 to 2016.

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2015	**$ 87**	**$ 330**
Emera Florida and New Mexico	63	172
Emera Caribbean	(6)	16
Emera Energy	(30)	(82)
NSPML and LIL AFUDC earnings	7	21
Acquisition and financing costs related to the acquisition of TECO Energy	43	(113)
TECO Energy post-acquisition financing costs	(44)	(93)
Gain (loss) on sale of APUC common shares	(10)	136
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	–	53
Gain on BLPC SIF regulatory liability	–	43
Emera Energy's recognition of fuel taxes for 2013 through March 2016	–	(12)
2015 gain on the sale of NWP	–	(12)
Other	(6)	16
Adjusted net income – 2016	**$ 104**	**$ 475**

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31 **2016**	 2015	Year ended December 31 **2016**	 2015	 2014
Operating revenues	**$ 1,513**	$ 731	**$ 4,277**	$ 2,789	$ 2,939
Income from operations	**208**	149	**555**	508	668
Net income attributable to common shareholders	**70**	192	**227**	397	407
After-tax mark-to-market gain (loss)	**(34)**	105	**(248)**	67	88
Adjusted net income attributable to common shareholders	**104**	87	**475**	330	319
Earnings per common share – basic	**$ 0.34**	$ 1.31	**$ 1.33**	$ 2.72	$ 2.84
Earnings per common share – diluted	**$ 0.34**	$ 1.30	**$ 1.32**	$ 2.71	$ 2.82
Adjusted earnings per common share – basic	**$ 0.51**	$ 0.59	**$ 2.77**	$ 2.26	$ 2.23
Dividends per common share declared	**$ —**	$ —	**$ 1.9950**	$ 1.6625	$ 1.4750
Adjusted EBITDA	**$ 498**	$ 259	**$ 1,744**	$ 1,031	$ 946

For the millions of Canadian dollars	Three months ended December 31 **2016**	 2015	Year ended December 31 **2016**	 2015	 2014
Operating Unit Contributions to Adjusted Net Income					
Emera Florida and New Mexico	**$ 63**	$ —	**$ 172**	$ —	$ —
NSPI	**34**	40	**130**	130	125
Emera Maine	**11**	5	**47**	45	42
Emera Caribbean	**8**	14	**100**	41	29
Emera Energy	**5**	35	**24**	130	98
Corporate and Other	**(17)**	(7)	**2**	(16)	25
Adjusted net income attributable to common shareholders	**$ 104**	$ 87	**$ 475**	$ 330	$ 319
After-tax mark-to-market gain (loss)	**(34)**	105	**(248)**	67	88
Net income attributable to common shareholders	**$ 70**	$ 192	**$ 227**	$ 397	$ 407

For the millions of Canadian dollars	Year ended December 31 **2016**	 2015	 2014
Operating cash flow before changes in working capital	**$ 919**	$ 776	$ 716
Change in working capital	**134**	(102)	46
Operating cash flow	**$ 1,053**	$ 674	$ 762
Investing cash flow	**$ (9,105)**	$ (124)	$ (711)
Financing cash flow	**$ 7,448**	$ 221	$ 58

As at millions of Canadian dollars	December 31 **2016**	 2015	 2014
Working capital	**$ 301**	$ 600	$ 357
Total assets [1]	**$ 29,221**	$ 12,039	$ 9,853
Total long-term liabilities [1]	**$ 18,681**	$ 6,338	$ 5,024

(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 2016

Emera Consolidated Statements of Income

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated electric	**$ 1,136**	$ 521	**$ 3,437**	$ 2,141	$ 2,064
Operating revenues – regulated gas	**282**	13	**499**	52	49
Operating revenues – non-regulated	**95**	197	**341**	596	826
Total operating revenues	**1,513**	731	**4,277**	2,789	2,939
Regulated fuel for generation and purchased power	**412**	200	**1,222**	815	844
Regulated cost of natural gas	**108**	—	**177**	—	—
Regulated fuel adjustment mechanism and fixed cost deferrals	**13**	11	**61**	42	47
Non-regulated fuel for generation and purchased power	**70**	91	**313**	336	401
Non-regulated direct costs	**22**	4	**29**	19	31
Operating, maintenance and general	**391**	173	**1,137**	666	561
Provincial, state and municipal taxes	**77**	15	**195**	63	58
Depreciation and amortization	**212**	88	**588**	340	329
Total operating expenses	**1,305**	582	**3,722**	2,281	2,271
Income from operations	**208**	149	**555**	508	668
Income from equity investments	**21**	26	**100**	108	66
Other income (expenses), net	**5**	115	**174**	141	12
Interest expense, net	**169**	70	**585**	212	180
Income before provision for income taxes	**65**	220	**244**	545	566
Income tax expense (recovery)	**(6)**	21	**(22)**	93	113
Net income	**71**	199	**266**	452	453
Non-controlling interest in subsidiaries	**1**	7	**11**	25	20
Net income of Emera Incorporated	**70**	192	**255**	427	433
Preferred stock dividends	**—**	—	**28**	30	26
Net income attributable to common shareholders	**70**	192	**227**	397	407
After-tax mark-to-market gain (loss)	**(34)**	105	**(248)**	67	88
Adjusted net income attributable to common shareholders	**$ 104**	$ 87	**$ 475**	$ 330	$ 319
Earnings per common share – basic	**$ 0.34**	$ 1.31	**$ 1.33**	$ 2.72	$ 2.84
Earnings per common share – diluted	**$ 0.34**	$ 1.30	**$ 1.32**	$ 2.71	$ 2.82
Adjusted earnings per common share – basic	**$ 0.51**	$ 0.59	**$ 2.77**	$ 2.26	$ 2.23

Emera's consolidated net income attributable to common shareholders decreased $122 million to $70 million in Q4 2016 compared to $192 million for the same period in 2015. For the year ended December 31, 2016, Emera's consolidated net income attributable to common shareholders decreased $170 million to $227 million compared to $397 million in 2015.

Q4 Consolidated Income Statement Highlights

Operational Results

Income from operations increased $59 million to $208 million in Q4 2016 compared to $149 million in the same quarter in 2015 primarily due to the contribution of Emera Florida and New Mexico and lower acquisition costs compared to Q4 2015. These increases were partially offset by unfavourable mark-to-market changes of $60 million, decreased margin at the NEGG Facilities and Emera Energy's decreased marketing and trading margin.

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

Total operating revenues increased $782 million to $1,513 million in Q4 2016 compared to $731 million in Q4 2015 primarily due to:
- $881 million increase from Emera Florida and New Mexico;
- $78 million decrease from changes in mark-to-market impacts; and
- $43 million decrease at the NEGG Facilities primarily due to lower hedged power prices.

Total operating expenses increased $723 million to $1,305 million in Q4 2016 compared to $582 million in Q4 2015, primarily due to the addition of expenses from Emera Florida and New Mexico, partially offset by decreased TECO Energy acquisition costs compared to Q4 2015.

Other income (expenses), net

Other income decreased $110 million to $5 million in Q4 2016 compared to $115 million in the same period in 2015. 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 Debenture Offering for the pending TECO Energy acquisition in Q4 2015, and a $12 million pre-tax loss on the sale of APUC common shares in Q4 2016.

Interest expense, net

Interest expense, net increased $99 million in Q4 2016 to $169 million compared to $70 million in the same period in 2015, primarily due to financing related to the TECO Energy acquisition and interest expense from Emera Florida and New Mexico.

Income tax expense (recovery)

Income tax expense decreased $27 million to a $6 million recovery in Q4 2016 compared to a $21 million expense for the same period in 2015 primarily due to decreased income before provision for income taxes. This was partially offset by the non-deductible portion of mark-to-market losses on USD-denominated currency and forward contracts related to the TECO Energy acquisition in Q4 2015.

2016 Consolidated Income Statement and Operating Cash Flow Highlights

Operational Results

Income from operations increased $47 million to $555 million for the year ended December 31, 2016 compared to $508 million in 2015 primarily due to the contribution from Emera Florida and New Mexico. This is partially offset by higher mark-to-market losses of $144 million, increased costs related to the acquisition of TECO Energy, decreased margin at the NEGG Facilities, including recognizing a $20 million liability for state tax on natural gas sales made from November 2013 through March 2016, and Emera Energy's decreased marketing and trading margin.

Total operating revenues increased $1,488 million to $4,277 million for the year ended December 31, 2016 compared to $2,789 million in the same period in 2015 primarily due to:

- $1,839 million increase from Emera Florida and New Mexico;
- $167 million decrease from changes in mark-to-market impacts;
- $84 million decrease at the New England Gas Generating Facilities primarily due to lower hedged power prices, partially offset by higher sales volumes as a result of fewer planned outage hours at the Bridgeport Facility in 2016;
- $61 million decrease at NSPI reflecting lower sales volumes due to weather and decreased fuel related electricity pricing; and
- $27 million decrease in Emera Energy Services reflecting less favourable market conditions year-over-year, partially offset by higher Q1 2016 margin resulting from a stronger USD and growth in the volume of business.

Total operating expenses increased $1,441 million to $3,722 million for the year ended December 31, 2016 compared to $2,281 million in 2015. This was primarily due to the addition of expenses from Emera Florida and New Mexico and increased acquisition costs related to the TECO Energy acquisition, partially offset by decreased regulated fuel for generation and purchased power reflecting changes in commodity prices and lower sales volumes at NSPI, and changes in mark-to-market impacts in Emera Energy.

Other income (expenses), net

Other income increased $33 million to $174 million for the year ended December 31, 2016 compared to $141 million in the same period in 2015. This was primarily due to a $160 million pre-tax gain on the sale of 63 million common shares of APUC, a $63 million pre-tax gain on conversion of 12.9 million APUC subscription receipts and dividend equivalents, and a $53 million pre-tax gain on the BLPC SIF regulatory liability. This was partially offset by mark-to-market losses relating to the TECO Energy acquisition related USD-denominated currency and forward contracts and the 2015 gain on the sale of NWP.

Interest expense, net

Interest expense, net increased $373 million year-to-date in 2016 to $585 million compared to $212 million in 2015. This was primarily due to the new financing related to the TECO Energy acquisition, interest and the Beneficial Conversion Feature on the Convertible Debentures, as well as interest expense from Emera Florida and New Mexico.

Income tax expense (recovery)

Income tax expense decreased $115 million to a $22 million recovery for the year ended December 31, 2016 compared to a $93 million expense in 2015 primarily due to decreased income before provision for income taxes, the non-taxable portion of gains on APUC transactions and deferred income taxes on regulated income recorded as regulatory assets and liabilities. This was partially offset by the non-deductible portion of mark-to-market losses on USD-denominated currency and forward contracts related to the TECO Energy acquisition.

Net cash provided by operating activities

Net cash provided by operating activities in 2016 increased $379 million to $1,053 million compared to $674 million during the same period in 2015.

Cash from operations before changes in working capital increased by $143 million primarily due to the contribution from Emera Florida and New Mexico, partially offset by acquisition and financing costs related to the TECO Energy acquisition, and decreased margin at the NEGG Facilities.

Changes in working capital increased operating cash flows by $236 million primarily due to decreased fuel inventory and receivables as a result of lower sales at NSPI, favourable changes in cash collateral positions on derivative instruments at NSPI, the contribution from Emera Florida and New Mexico, and the timing of income tax payments at NSPI and Emera Energy Services.

Effect of Foreign Currency Translation

Emera operates globally, with an increasing amount of the Company's adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and particularly the US dollar, which could positively or adversely affect results. Consistent with the Company's risk management policies, it manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

Components of net income and adjusted net income are translated at the weighted average rate of exchange. The table below includes Emera's significant segments whose contribution to adjusted earnings are recorded in US dollar currency.

	Three months ended December 31		Year ended December 31	
millions of US dollars	**2016**	2015	**2016**	2015
Emera Florida and New Mexico	**$ 47**	$ —	**$ 131**	$ —
Emera Maine	**9**	4	**36**	36
Emera Caribbean	**6**	10	**77**	31
Emera Energy [(1)]	**5**	26	**25**	104
	67	40	**269**	171
Corporate and Other [(2)]	**(29)**	3	**(59)**	8
Total	**$ 38**	$ 43	**$ 210**	$ 179
Weighted average FX rate for period	**$ 1.32**	$ 1.33	**$ 1.32**	$ 1.27

(1) Includes Emera Energy's US dollar adjusted net income from EES, NEGG and Bear Swamp.
(2) Corporate and Other includes interest expense on US dollar denominated debt, net of interest income on an intercompany US dollar loan to Emera Energy.

OUTLOOK

The acquisition of TECO Energy has changed Emera's business mix and enabled the Company to meet its strategic goal of having 75 to 85 per cent of its adjusted net income derived from regulated operations. The TECO Energy acquisition adds diversity to Emera's operations, meets Emera's strategic objective of expanding Emera's operations to include gas distribution services, and expands Emera's markets into higher growth regions. TECO Energy's operations and opportunities align well with Emera's strategy to invest in the transformation of electricity generation from higher to lower carbon intensity and providing cleaner and affordable energy solutions for customers. The addition of these regulated businesses may result in a material increase in earnings and cash flow as compared to the expected financial results prior to the acquisition.

Emera's operations are affected by the US dollar relative to the Canadian dollar. The effect on Emera's net income is noteworthy, as it is expected that approximately 70 per cent of Emera's future adjusted net income will be derived from subsidiaries with a US functional currency. Emera's consolidated net income and cash flows will be impacted in the future to a greater extent by movements in the US dollar relative to the Canadian dollar as a result of the TECO Energy acquisition.

Emera Florida and New Mexico

Emera Florida and New Mexico includes the following:

- TECO Energy, the parent company of the companies discussed below.
- TEC, which consists of two divisions:
  - Tampa Electric, a vertically-integrated regulated electric utility engaged in the generation, transmission and distribution of electricity serving customers in West Central Florida.
  - PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida.
- NMGC, a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico.
- TECO Finance, a financing subsidiary of TECO Energy.

Tampa Electric

With nearly $7.0 billion USD of assets and approximately 736,000 customers, at December 31, 2016, Tampa Electric owned 4,730 megawatts ("MW") of generating capacity, of which 60 per cent was natural gas-fired, 35 per cent was conventional coal-fired and 5 per cent coal and petroleum coke ("petcoke") using integrated gasification combined cycle technology. Tampa Electric owns 2,140 kilometres of transmission facilities and 18,370 kilometres of distribution facilities.

Tampa Electric is regulated by the FPSC 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 consistent with investments of comparable risk to investors. Tampa Electric's target regulated return on equity ("ROE") range is currently 9.25 per cent to 11.25 per cent, on an allowed equity capital structure of 54 per cent. 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.

Tampa Electric has a fuel-recovery clause, approved by the FPSC, allowing recovery of actual fuel costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs for generation and purchased power and certain fuel-related costs ("Fuel Costs") and amounts recovered from customers through electricity rates are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year. Tampa Electric has an environmental cost recovery clause which allows the company to earn a return on investments in new facilities to comply with new environmental regulations and to recover the costs to operate and maintain these facilities. Through its conservation cost recovery clause, Tampa Electric also offers its customers a comprehensive array of residential and commercial programs that have enabled the company to meet its required demand side management goals, reduce weather-sensitive peak demand and conserve energy.

Florida utilities must obtain franchises to operate in certain 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; all are expected to be renewed under similar terms and conditions.

Peoples Gas System

With more than $1.1 billion USD of assets and approximately 374,000 customers, the PGS system includes approximately 19,950 kilometres of natural gas mains and 11,265 kilometres of service lines. Gas mains are distribution lines that serve as a common source of supply for more than one service line. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) is 1.9 billion therms.

PGS is regulated by the FPSC under a cost-of-service model, with rates established to recover prudently incurred costs of providing gas distribution service to customers, and to provide an appropriate return consistent with investments of comparable risk to investors. In December 2016, PGS entered into a settlement agreement with the Office of Public Counsel regarding its filed depreciation study. On February 7, 2017, the FPSC approved the settlement agreement. The settlement agreement resulted in a $16 million USD annual reduction to PGS' depreciation expense beginning in 2016 and accelerated the amortization of PGS' regulatory asset associated with the environmental liability for current and future remediation costs related to former Manufactured Gas Plant ("MGP") sites. The settlement requires that at least $32 million USD of MGP amortization be expensed for the period 2016 through 2020 and of that at least $21 million USD to occur over 2016 and 2017. In 2016, PGS recorded $16 million USD of MGP amortization acceleration and as a result offset the $16 million USD reduction in 2016 depreciation expense. Absent any rate case filing, through 2020, the bottom of the allowed ROE range for PGS will be decreased 50 basis points to 9.25 per cent and the top of the range will remain unchanged at 11.75 per cent. The ROE of 10.75 per cent will continue to be used for the calculation of the return on investments for clauses. No change in customer rates resulted from this settlement agreement.

New Mexico Gas Company, Inc.

With over $0.8 billion USD of assets and approximately 522,000 customers, NMGC serves about 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,600 kilometres of transmission lines and 16,400 kilometres of mains. Annual natural gas throughput is approximately 775 million therms. 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.

NMGC is regulated by the NMPRC under a cost-of-service model, with rates established to recover prudently incurred costs of providing gas distribution service to customers, and to provide an appropriate return consistent with investments of comparable risk to investors. NMGC's rates were established in a 2012 rate case settlement and are frozen until December 31, 2017 per the June 2016 NMPRC order (the "Order") approving Emera's acquisition of TECO Energy. Under the Order, NMGC will also provide customer credits of $4 million USD annually through June 30, 2018.

Emera Florida and New Mexico Outlook

Emera Florida and New Mexico earnings are most directly impacted by the earned rate of return on equity and the capital structures approved by the FPSC and NMPRC, the prudent management of operating costs, the approved recovery of regulatory deferrals, and the timing and amount of capital expenditures.

The Florida utilities anticipate earning within their allowed ROE ranges in 2017 and expect rate base and earnings to be higher than prior years. Tampa Electric and PGS expect slightly higher customer growth rates in 2017 than those experienced in 2016, reflective of economic growth in Florida. Assuming normal weather, sales are expected to increase consistent with customer growth. In accordance with the 2013 settlement agreement approved by the FPSC, Tampa Electric increased base rates by $110 million USD on January 16, 2017, the commercial operation date of the Polk Power Station expansion project. This expansion project adds an additional 460 MW of generating capacity and invests in the related transmission system improvements needed to support the additional generation.

NMGC expects earnings to be consistent with prior years. Customer growth rates are expected to be slightly higher in 2017 than in 2016, reflecting expectations for housing starts and new connections. Assuming normal weather, sales growth is expected to be consistent with customer growth and costs will increase slightly.

In 2017, Emera Florida and New Mexico expects to invest approximately $645 million USD in capital projects compared to $795 million USD in 2016. The 2016 capital expenditures included approximately $135 million USD for the Polk Power Station conversion project and $35 million USD for the Florida utilities' new customer relationship management and billing system, both of which went into service in January 2017. The 2017 capital expenditures include projects to support normal system reliability and growth at Tampa Electric, PGS and NMGC. Tampa Electric includes programs for transmission and distribution system storm hardening, distribution system modernization and automated metering equipment, transmission system reliability requirements and investments in utility scale solar photo voltaic projects. PGS will make investments to expand the system and support customer growth, including high sales volume compressed natural gas fuelling stations, and continue with replacement of cast iron and bare steel pipe. NMGC will undertake a project relocating a portion of the gas pipeline feeding Taos, New Mexico and will invest in a new customer relationship management and billing system.

NSPI

NSPI is a fully-integrated regulated electric utility and is the primary electricity supplier in Nova Scotia, Canada. NSPI has $4.8 billion of assets and provides electricity generation, transmission and distribution services to approximately 511,000 customers. The Company owns 2,487 MW of generating capacity, of which approximately 43 per cent is coal-fired; 29 per cent is natural gas and/or oil; 19 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fuelled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 530 MW of capacity. This is expected to increase to 547 MW of capacity in 2017. IPP generation includes wind, tidal, biogas and biomass-fuelled generation. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

NSPI is a public utility as defined in the *Public Utilities Act (Nova Scotia)* ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are 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 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 approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent.

NSPI has a Fuel Adjustment Mechanism ("FAM"), approved by the UARB, allowing NSPI to recover fluctuating fuel costs from customers through annual fuel rate adjustments. Differences between 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.

In December 2015, the UARB approved NSPI's 2016 fuel rates and its recovery of prior period unrecovered Fuel Costs. The approved customer rates reset the base cost of fuel rates for 2016. In addition, they approved a $12 million recovery of prior years' unrecovered Fuel Costs in 2016. This resulted in a combined average rate decrease for customers of approximately 1 per cent in 2016. The rates and recovery of these costs began on January 1, 2016.

On December 18, 2015, the Province enacted the *Electricity Plan Implementation (2015) Act, ("Electricity Plan Act")*, which required NSPI to file a three-year stability plan for Fuel Costs and a General Rate Application ("GRA") for non-fuel costs if required by April 30, 2016. On March 7, 2016, NSPI announced that it would not file a GRA related to non-fuel electricity rates for the 2017 to 2019 period and NSPI filed the stability plan for Fuel Costs with the UARB for 2017 through 2019.

On July 19, 2016, the UARB approved a Consensus Agreement between NSPI and customer representatives related to the Rate Stability Plan for Fuel Costs for 2017 through 2019. Subsequently, certain customer representatives requested changes resulting in amended rates that were approved by the UARB on November 15, 2016 and results in an average annual rate increase of 1.5 per cent for each of these three years.

On December 12, 2016, the UARB approved the refund of over-recovered Fuel Costs in 2016 to customers. The over-recovered Fuel Costs balance at the end of 2016 will be refunded to customers through a one-time credit on their bills prior to April 30, 2017 and will be based on individual electricity usage in 2016. The balance to be refunded to customers is approximately $36 million.

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.

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 stability plan for Fuel Costs in Q1 2016 with the UARB. NSPI also announced that it would not file a GRA for non-fuel costs for the 2017 through 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 approval of a market framework to enable independent renewable energy producers licenced by the UARB to sell directly to retail customers. The UARB issued a decision in 2016 approving the Company's proposed framework. Potential retailers must apply to the UARB for approval of a licence to sell low-impact renewable electricity generated in Nova Scotia. Licenced retailers who enter this retail market must pay tariffs to use NSPI's systems for delivering their renewable energy, to ensure the supply of electricity to their customers and to ensure NSPI customers do not bear the cost of this new market.

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. The Company continues to work with officials at both of these levels of government to comply with these regulations in an integrated way, maximizing efficiency of emission control measures.

In November 2014, the Government of Canada and the Province of Nova Scotia entered into a greenhouse gas ("GHG") emission regulations equivalency agreement, which allows NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

In March 2016, Canada's First Ministers issued the "Vancouver Declaration" on clean growth and climate change. First Ministers agreed to develop a Pan-Canadian Framework and implement it by early 2017. Four working groups, comprised of federal, provincial and territorial officials were established to provide recommendations and research to the federal government. NSPI provided input into this process through the Nova Scotia government, the Government of Canada and directly to the working groups through the submission of a discussion paper.

In October 2016, the Government of Canada announced that the Pan-Canadian Framework would include a national price on carbon component, implemented by 2018 through either a carbon tax or a cap and trade system, applicable in each province except those which enact their own comparable carbon pricing mechanism by that time.

On November 21, 2016, the Government of Canada announced a second component of the plan would include an accelerated plan to phase out coal in Canada, to transition Canada's electricity system towards 90 per cent non-emitting generation sources by 2030.

On the same day the Province of Nova Scotia and the Government of Canada made two announcements regarding Nova Scotia's participation in the Pan-Canadian plan:

Carbon pricing component

An agreement in principle covering the carbon component had been reached and will be governed on the following principles:

- Nova Scotia will adopt a province-wide 2030 emissions reduction target equal or greater than Canada's target of a 30 per cent reduction from 2005 levels by 2030;
- Nova Scotia will implement an agreed upon cap and trade system; and
- The Province of Nova Scotia and the Government of Canada will agree upon a methodology and scenarios for the modelling of projected greenhouse gas emissions to support the development of Nova Scotia's cap and trade system.

Accelerated phase-out of coal component

Nova Scotia and the Government of Canada will establish a new equivalency agreement that will enable the province to move directly from fossil fuels to clean energy sources and enable NSPI's coal-fired plants to operate at some capacity beyond 2030.

On December 9, 2016 the Government of Canada and eight provinces (including Nova Scotia) signed the Pan-Canadian Framework on Clean Growth and Climate Change. The Government of Canada has committed to ensuring that the provinces and territories have the flexibility to design their own policies and programs to meet emission-reduction targets, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies. Details under the agreements are expected to be finalized by the end of 2017. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions would be recoverable from customers under NSPI's regulatory framework. NSPI will continue to work with both the Province of Nova Scotia and the Government of Canada as the details of the agreements are finalized and to advance solutions that are in the best interest of customers.

The Government of Canada has indicated their intention to resume discussions regarding Base Level Industrial Emission Requirements ("BLIER"s) for sulphur dioxide and nitrogen dioxide and have outlined their intention to develop a Clean Energy Standard for natural gas and possibly diesel. The details of both processes are not yet known. NSPI will participate in these processes.

NSPI's earnings are most directly impacted by the range of ROE and capital structure approved by the UARB; the prudent management and approved recovery of operating costs, demand and generation load, weather, the approved recovery of regulatory deferrals and the timing and amount of capital expenditures. NSPI anticipates earning within its allowed ROE range in 2017 and expects its earnings and rate base to generally be consistent with prior years.

In 2017, NSPI expects to invest approximately $398 million, including AFUDC, in capital projects compared to $309 million in 2016. This increase is primarily driven by increased spending on information technology projects and Maritime Link related Transmission projects.

Emera Maine

Emera Maine is a transmission and distribution ("T&D") electric utility with assets of approximately $1.1 billion serving approximately 157,000 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 T&D networks. Emera Maine owns and operates approximately 1,800 kilometres of transmission facilities and 15,000 kilometres of distribution facilities.

Approximately 52 per cent of Emera Maine's electric revenue represents distribution operations, 35 per cent is associated with local transmission operations and 13 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

Emera Maine's earnings are most directly impacted by the combined impacts of the range of rates of ROE and rate base approved by its regulators, the prudent management and approved recovery of operating costs, load (including the effects of weather), and the timing and amount of capital expenditures.

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 December 21, 2016 the ROE upon which rates are set was 9.55 per cent with a common equity component of 49 per cent. On December 21, 2016, Emera Maine's distribution rates increased 3.75 per cent which was based on a 9 per cent ROE and a common equity component of 49 per cent.

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. The common equity component is based upon the prior calendar year actual average balances. On October 16, 2014, FERC issued an order in response to a challenge of the ISO-New England ("ISO-NE") Open Access Transmission Tariff base ROE compliant reducing the ROE from 11.14 per cent to 10.57 per cent for the period of October 1, 2011 to December 31, 2012 and set 10.57 per cent as the ROE rate effective October 16, 2014. The October 16, 2014 FERC order is currently under appeal in the DC Circuit Court and there are three additional pending complaints filed with the FERC to challenge the ISO-New England ("ISO-NE") Open Access Transmission Tariff allowed base ROE.

Effective June 1, 2016, the average retail transmission rates for the Bangor Hydro District increased by approximately 2 per cent in connection with its annual transmission formula rate filing (2015 – increased by 21 per cent). The increase is associated primarily with the recovery of increased transmission plant in service and as a result the prior year tariff rate including a rate refund related to the aforementioned FERC ROE decision.

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. 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. The common equity component is based upon the prior calendar year average balances. On October 16, 2014, FERC issued an order in response to a challenge of the ISO-NE Open Access Transmission Tariff reducing Bangor Hydro District's ROE for these transmission investments which ranged from 11.64 per cent up to 12.64 per cent to 11.07 per cent up to 11.74 per cent. There are currently three pending aforementioned complaints filed with FERC.

On June 1, 2016, Bangor District's regionally recoverable transmission investments and expenses increased by 9 per cent (2015 – decreased by 6 per cent).

As at December 31, 2016, the Company had accrued $5 million pre-tax ($4 million USD) associated with the first two pending FERC ROE complaints (2015 – $7 million or $5 million USD). No reserve has been recorded for the third pending complaint as the outcome is considered uncertain. Refunds for the first FERC ROE complaint that FERC issued a ruling upon on October 16, 2014 were made to customers over a one-year period which began with the June 1, 2015 rate change and ended May 31, 2016 resulting in the reduction to the accrued reserve.

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 ROE for transmission operations is 10.2 per cent. The common equity component is based upon the prior calendar year actual average balances.

Effective June 1, 2016 the transmission rates for the MPS District increased by approximately 43 per cent for wholesale customers (2015 – decreased by 1 per cent) and on July 1, 2016 increased by 36 per cent for retail customers (2015 – decreased by 22 per cent) in connection with its annual transmission formula rate filing. Transmission rates in the MPS District for retail and wholesale customers can vary from year to year due to changes in the amount of export sales revenue received, the amount of transmission plant in service, the amount of operating cost to maintain the transmission system, and the approved ROE. The increase in the retail and wholesale transmission rates in 2016 is due to the increased investment of plant in service required to replace aging infrastructure. On April 1, 2015, as amended May 1, 2015, Emera Maine filed a revised Maine Public District (MPD) Open Access Transmission Tariff formula which was challenged by the Maine Customer Group and is currently subject to settlement discussions.

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. As a result, 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. 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.

Stranded cost recovery rates for Bangor Hydro District are set on a 5.9 per cent ROE, with a common equity component of 48 per cent. For MPS District, rates are set on a 6.75 per cent ROE with a common equity component of 48 per cent.

Emera Maine's 2017 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure resulting in modest growth in earnings.

Emera Maine expects to spend approximately $70 million USD (2016 – $69 million USD actual) in capital projects in 2017.

Emera Caribbean

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

Consolidated Investments

- 100.0 per cent (December 31, 2015 – 95.5 per cent) investment in ECI and its wholly owned subsidiary BLPC, a vertically integrated utility that is the provider of electricity in Barbados. BLPC serves 126,000 customers and is regulated by the Fair Trading Commission, Barbados. BLPC owns 239 MW of oil-fired generation, 150 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2016 is 10.0 per cent. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. On February 24, 2016, Emera completed the purchase of the remaining 4.5 per cent of common shares from minority shareholders of ECI.
- 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in GBPC, which is a vertically integrated utility and a sole provider of electricity on Grand Bahama Island. GBPC serves 19,000 customers and is regulated by the GBPA. GBPC owns 98 MW of oil-fired generation, 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. Effective February 1, 2016, the GBPA approved GBPC's regulated return on rate base of 8.8 per cent applicable for the 2016 through 2018 period. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. In December 2016, the GBPA approved the all-in rates for electricity (fuel and base rates) for the 2017 to 2021 periods to be held consistent with the 2016 rates. The approval includes the recovery of Hurricane Matthew related costs (as discussed below).
- 51.9 per cent (December 31, 2015 – 49.6 per cent indirect controlling interest), through ECI, in Domlec, an integrated utility on the island of Dominica. Domlec serves 36,000 customers and is regulated by the IRC. Domlec owns 20 MW of oil-fired generation, 7 MW of hydro production, 497 kilometres of transmission facilities and 716 kilometres of distribution facilities. Domlec's approved allowable regulated return on rate base for 2016 is 15.0 per cent. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.

Equity Investment

- 19.1 per cent (December 31, 2015 – 18.2 per cent indirect interest), through ECI, in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia. Lucelec is regulated by the National Utility Regulatory Commission (NURC) which was established in 2016 to regulate utility services in St Lucia. Lucelec was previously regulated by the Government of St Lucia. The investment in Lucelec is accounted for on the equity basis.

On December 7, 2016, Emera sold its 50.0 per cent direct and 30.4 per cent indirect interest in GBPC to ECI. The transaction simplifies the Emera Caribbean reporting structure and allows the Caribbean to be managed from a single entity. It also allows for greater cooperation between the Caribbean utilities, including further sharing of skills and increased efficiencies that can result in benefits to customers.

Earnings from Emera Caribbean are most directly impacted by the rates of return on rate base approved by their regulators, capital structure, prudent management, approved recovery of operating costs, load, and the timing and scale of capital expenditures.

The Barbados economy is predominantly driven by tourism and is forecasted to grow modestly in 2017. However, the April 2016 credit downgrades by Moody's (and more recently S&P in September 2016) of the long-term foreign and local currency sovereign ratings of Barbados, highlights the lack of market confidence that economic recovery will be sustained. The economy of Grand Bahama is generally correlated to the United States economy. On December 20, 2016, S&P lowered its foreign and local currency sovereign credit ratings on The Commonwealth of The Bahamas. This downgrade was driven by weak economic growth and spending pressure in The Bahamas as a result of Hurricane Matthew.

In October 2016, the island of Grand Bahama took a direct hit from Hurricane Matthew. Property damage on the island was extensive. GBPC's generation and substation infrastructure weathered the storm well, however over 2,100 transmission and distribution poles and related conduit were damaged or destroyed, as were many connections to customer homes. Restoration efforts have been completed with the support of other Emera affiliates. Post hurricane load is down approximately 10 per cent as compared to normal expectations; however, management anticipates that demand will recover to pre-storm levels by 2018.

Emera Caribbean has recorded $28 million USD of restoration costs associated with Hurricane Matthew with no impact to net income. $21 million USD has been recorded as a regulated asset amortized over five years and $7 million USD recorded as property, plant and equipment depreciating at an average 27 years. Both assets are included in rate base. In December 2016, the GBPA has approved the full recovery of the storm restoration costs in this manner.

In addition, the GBPA approved that over a 5 year period, 2017 to 2021, the all-in rate for electricity (fuel and base rates) will be held at 2016 levels. This is achievable as the company's fuel costs over this period are forecasted to decrease. Fuel costs are managed through a fuel hedging program which allows predictability of these costs. Any over recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory deferral, until such time as the deferral is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory deferral, the excess will be placed in a new storm reserve. If the Hurricane Matthew deferral is not fully recovered at the end of 5 years GBPC will have the opportunity to request recovery from customers in future rates.

With oil being the predominant fuel source for generation of electricity in the Caribbean, and with fuel costs directly passed through electricity rates to customers, any change in global fuel prices and resulting change in fuel costs will result in a similar change in customer rates and reported revenues. GBPC has implemented fuel hedging strategies to provide increased certainty to customers as to fuel costs and electricity rates. In support of reducing carbon emissions and exposure to carbon based fuel sources, BLPC recently commissioned a 10 megawatt solar facility in Barbados, which became operational in Q2 2016. Additional renewable energy generation investments are being explored.

Overall, Emera Caribbean 2017 earnings are expected to be slightly less than prior years, excluding the impact of the Q2 2016 gain recognized on the SIF regulatory liability. This is a result of expected short-term load decline in GBPC from Hurricane Matthew and higher interest charges in ECI on new debt issued in Q4 2016.

Emera Caribbean plans to invest approximately $109 million USD in capital programs in 2017 (2016 – $49 million USD actual). This increase is due to spending on renewable, advanced metering infrastructure and street lighting projects.

Emera Energy

Emera Energy includes the following:
- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business.
- Emera Energy Generation ("EEG"), a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada with 1,435 megawatts ("MW") of total capacity.
- Equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts. The investment in Bear Swamp is accounted for on an equity basis.

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 and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 generally providing the greatest opportunity for earnings.

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.

In addition to capitalizing on volatility-driven market opportunities, Emera Energy Services expects to continue to grow organically by building market share through strong customer service, optimizing Emera Energy's portfolio to build on power margin, and expanding its geographic reach to adjacent markets, including the Mid-Atlantic region.

The business is generally expected to deliver net earnings of $15 million to $30 million USD, with the opportunity for upside when market conditions present.

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 NEGG Facilities. Efficient operations of the fleet to ensure unit availability, cost management and effective commercial performance are key success factors.

Adjusted earnings from Emera Energy's generating assets in 2017 are expected to be higher than 2016, reflecting higher capacity prices (see table below) that come into effect mid-year 2017. Emera Energy expects this increase to be partially offset by lower market spark spreads and reduced hedging opportunities year-over-year.

Equity Investments

Bear Swamp's adjusted earnings are expected to be higher in 2017 mainly due to higher capacity revenues and fewer planned maintenance outages as compared to 2016.

Capacity Payment

In addition to energy margins and ancillary revenue, the NEGG Facilities and Bear Swamp earn revenue from capacity payments through the forward capacity market ("FCM"), the annual reconfiguration capacity market and the monthly reconfiguration capacity market. Prices for the FCM, the largest of the components, are determined through an auction process held annually, three years in advance, thus providing revenue visibility to 2021, 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 NEGG Facilities, and Emera Energy's 50.0 per cent interest in Bear Swamp.

Forward Capacity Auction ("FCA") Year	Clearing Price in $/kW-month (in USD)	Approximate Estimated Annual Capacity Revenue (in USD) (1)
FCA 7 (June 2016 to May 2017)	$3.15	$40 million
FCA 8 (June 2017 to May 2018)	$7.025	$100 million
FCA 9 (June 2018 to May 2019)	$9.55 and $11.08 (1)	$145 million
FCA 10 (June 2019 to May 2020)	$7.03	$106 million
FCA 11 (June 2020 to May 2021)	$5.297	$80 million

(1) $11.08 was awarded for the Southeast Massachusetts/Rhode Island zone only and, as such, applies only to Tiverton.

In 2017, Emera Energy expects to invest approximately $46 million (2016 – $39 million actual) in capital projects related to its generating assets in order to further improve reliability and increase plant capacity.

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" and costs associated with corporate activities that are not directly allocated to the operations of Emera's subsidiaries and investments.

Other

Other includes the following consolidated and non-consolidated investments:

Consolidated Investments

- Brunswick Pipeline is an NEB regulated, 145-kilometre pipeline that transports natural gas from Saint John, New Brunswick, to markets in the northeastern United States. The pipeline is contracted under a 25-year firm service agreement with Repsol Energy Canada that expires in 2034. The service agreement is accounted for as a direct financing lease.
- 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.
- Emera Utility Services ("EUS") is a utility services contractor primarily operating in Atlantic Canada.
- Emera US Holdings Inc. is a wholly owned holding company for certain of Emera's assets located in the United States.
- Emera US Finance LP is a wholly owned financing subsidiary of Emera.

Non-consolidated investments

- Emera's 100 per cent investment in ENL, which holds investments in the following:
  - Emera's 100 per cent investment in NSPML, a $1.56 billion transmission project, including two 170-kilometre subsea cables, connecting the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the return on equity component of AFUDC, which will continue until the Maritime Link Project goes into service. This project is scheduled to be completed in Q4 2017 and go into service by January 1, 2018.
  - Emera's 62.7 per cent (December 31, 2015 – 55.1 per cent) investment in the partnership capital of LIL, a $3.4 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon completion and final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. Nalcor Energy has indicated that the project will be in service in Q2 2018.
- Emera's 12.9 per cent investment in M&NP.
- On December 8, 2016 Emera sold the Company's remaining 4.7 per cent (December 31, 2015 – 19.6 per cent) investment in APUC. APUC is a diversified generation, transmission and distribution utility traded on the Toronto Stock Exchange ("TSX") under the symbol "AQN". On May 24, 2016, Emera completed the sale of 50.1 million common shares of APUC, representing approximately 19.3 per cent of APUC's issued and outstanding common shares. On June 30, 2016, Emera exchanged 12.9 million APUC subscription receipts and dividend equivalents into 12.9 million APUC common shares. The resulting gains on the sale of the investment and conversion of subscription receipts and dividend equivalents into common shares are recorded in "Other income (expenses), net" on the Consolidated Statements of Income. APUC was accounted for on the equity basis, and Emera's proportioned share of APUC's earnings was included in the Consolidated Statements of Income until its partial sale on May 24, 2016. Since that time and up until the disposition on December 8, 2016, the common shares of APUC were included in Investment securities on the Consolidated Balance Sheets, with dividend income recorded in Other income (expenses), net on the Consolidated Statements of Income.

Corporate and Other includes corporate related costs which are dependent on the level of business development activity and acquisition related initiatives. This segment includes corporate financing costs, 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 and capital lease accounting treatment of the Emera Brunswick Pipeline, which yields declining earnings over the life of the asset. In 2015 this segment also included the equity earnings from the company's investment in APUC.

Corporate and Other's contribution to consolidated adjusted net income is expected to be lower in 2017 primarily as the result of the 2016 gains associated with the sale of Emera's investment in APUC. This is partially offset by higher OM&G costs in 2016 related to the TECO Energy acquisition and lower forecasted 2017 interest costs as a result of permanent financing in place for the TECO Energy acquisition.

Corporate and Other, excluding ENL as discussed below, expects to spend approximately $13 million on property, plant and equipment in 2017 (2016 – $7 million actual).

ENL

NSP Maritime Link Inc. ("NSPML")

Through its subsidiary, NSP Maritime Link Inc., ENL had invested at December 31, 2016, $1.18 billion of equity, debt and working capital, including $132 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested $315 million in equity, comprised of $261 million in equity contributed and $54 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent.

ENL's future earnings contribution from the Maritime Link Project will be affected by the amount and timing of capital expenditures for 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 debt to equity ratio reached 70 to 30 per cent, respectively, which occurred in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70 to 30 per cent ratio, with equity contributions of $106 million made in 2016.

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. Abengoa S.A. has been under ongoing global creditor protection proceedings that hampered the company's ability to perform its work. As a result of Abengoa's failure to perform, NSPML notified Abengoa that it was in default of its contract. NSPML has terminated its contract with Abengoa.

In July 2016 NSPML announced EUS-Rokstad, a joint venture between EUS and Rokstad Power, would complete construction of the high-voltage direct current components of the transmission line. As part of the agreement entered into with NSPML, EUS has responsibility for approximately 50 kilometres of transmission line in Nova Scotia and Rokstad has responsibility for approximately 140 kilometres of transmission line on the island of Newfoundland. EUS and Rokstad Power are jointly and severally liable for completion of the project.

Maritime Link Project forecasted equity contributions for 2017 are $181 million, resulting in total equity contributions for the Project estimated to be $442 million.

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, with project costs currently estimated at $3.4 billion. As at December 31, 2016, ENL had invested $400 million, comprised of $355 million in equity and $45 million of accumulated equity earnings in LIL. Equity earnings are recorded based on an annual rate of 8.5 per cent of the equity invested (8.8 per cent prior to July 1, 2016). The ROE is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB"). Future earnings are dependent on the amount and timing of additional equity investments and the approved ROE. Total equity contributions for LIL in 2016 are $168 million.

LIL 2017 equity contributions by Emera are forecasted to be $55 million. The total equity contribution by Emera for the project is estimated to be approximately $600 million.

Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

Throughout construction of both ML and LIL, equity earnings in ENL are a result of AFUDC on the related projects. Therefore, 2017 equity earnings contribution from ENL will be higher in 2017 than 2016 as a result of Emera's continued equity contribution while under construction resulting in higher equity levels and therefore higher AFUDC earnings.

Consolidated Balance Sheets Highlights

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

millions of Canadian dollars	Total	Increase (Decrease) Due to Emera Florida and New Mexico	Other Increase (Decrease)	Explanation of Other Increase/Decrease
Assets				
Cash and cash equivalents	**$ (669)**	**$ 37**	**$ (706)**	Decreased primarily due to the cash paid for the acquisition of TECO Energy
Receivables, net	**436**	**350**	**86**	Increased primarily due to higher commodity prices and increased volumes at Emera Energy
Income taxes receivable, net of income taxes payable (current and long-term)	**9**	**(23)**	**32**	Increased primarily due to expected recovery of prior year income taxes at Emera Energy
Inventory	**158**	**233**	**(75)**	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)	**(142)**	**22**	**(164)**	Decreased primarily due to settlement and change in gas and power contracts at Emera Energy and mark-to-market adjustment on foreign exchange forward contracts in Emera Corporate
Regulatory assets (current and long-term)	**623**	**590**	**33**	Increased primarily due to the regulatory offset to deferred income taxes at Brunswick Pipeline and ENL
Property, plant and equipment, net of accumulated depreciation	**10,821**	**10,728**	**93**	Increased primarily due to the favourable effect of a stronger CAD on the translation of Emera's foreign subsidiaries and increased capital expenditures at NSPI, partially offset by depreciation
Investments subject to significant influence	**(198)**	**–**	**(198)**	Decreased primarily due to the sale of APUC common shares, partially offset by increased investment in LIL and NSPML. See discussion under "Significant Items Affecting Earnings"
Investment securities (current and long-term)	**(68)**	**–**	**(68)**	Decreased primarily due to the withdrawal of investments in the SIF
Goodwill	**5,949**	**–**	**5,949**	Increased due to the TECO Energy acquisition
Other assets (current and long-term)	**84**	**108**	**(24)**	Decreased primarily due to lower initial value of AMA's and the amortization of transportation assets

Consolidated Balance Sheets Highlights (continued)

millions of Canadian dollars	Total	Increase (Decrease) Due to Emera Florida and New Mexico	Other Increase (Decrease)	Explanation of Other Increase/Decrease
Liabilities and Equity				
Short-term debt and long-term debt (including current portion)	**11,680**	**5,635**	**6,045**	Increased primarily due to the issuance of long-term debt related to the TECO Energy acquisition and issuance of debt in the Caribbean
Accounts payable	**848**	**692**	**156**	Increased primarily due to higher commodity prices at Emera Energy and increased cash collateral position on derivative instruments at NSPI
Deferred income tax liabilities, net of deferred income tax assets	**817**	**905**	**(88)**	Decreased primarily due to additional tax losses and the change in derivative instruments
Convertible debentures	**(673)**	**–**	**(673)**	Decreased due to the conversion of the majority of the convertible debentures related to the TECO Energy acquisition into common shares
Derivative instruments (current and long-term)	**30**	**–**	**30**	Increased primarily due to changes in existing positions on AMA's and long-term natural gas contracts, partially offset by settlements of natural gas and power contracts at Emera Energy and commodity contracts at NSPI and GBPC
Regulatory liabilities (current and long-term)	**1,174**	**1,173**	**1**	The increase in NSPI's regulatory liability due to the increase in the FAM regulatory liability was partially offset by the reduction of SIF BLPC regulatory liability
Pension and post-retirement liabilities (current and long-term)	**417**	**396**	**21**	Increased primarily due to a reduction in the discount rate at NSPI
Other liabilities (current and long-term)	**244**	**218**	**26**	Increased primarily due to the timing of interest payments on the long-term debt related to the TECO Energy acquisition
Common stock	**2,581**	**–**	**2,581**	Increased primarily due to the conversion of the convertible debentures into common shares, the Q4 2016 issuance of 7.6 million common shares, and issuance of common stock for the dividend reinvestment program
Contributed surplus	**46**	**–**	**46**	Increased primarily due to the beneficial conversion feature discount on the convertible debentures related to the TECO Energy acquisition
Accumulated other comprehensive income	**(31)**	**99**	**(130)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and the adjustment to AOCI due to the sale of APUC common shares
Retained earnings	**(92)**	**172**	**(264)**	Decreased due to dividends paid in excess of net income
Non-controlling interest in subsidiaries	**(22)**	**–**	**(22)**	Decreased due to increased ownership by Emera in ECI

Developments

Conversion of Convertible Debentures

As at December 31, 2016, 52 million common shares of Emera were issued relating to the conversion of the Convertible Debentures, representing conversion into common shares of 99.6 per cent of the outstanding convertible debentures.

Increase in Common Dividend

On July 4, 2016, Emera's Board of Directors announced an increase in the annual common share dividend rate from $1.90 to $2.09. The first payment was effective August 15, 2016. Emera also extended its eight per cent annual dividend growth target from 2019 to 2020.

Acquisition of TECO Energy

On July 1, 2016, Emera acquired all of the outstanding common shares of TECO Energy for $27.55 USD per common share. The net cash purchase price totalled $8.4 billion ($6.5 billion USD), with an aggregate purchase price of $13.9 billion ($10.7 billion USD), including the assumption on closing of $5.5 billion ($4.2 billion USD) in US debt. The net cash purchase price was financed through: (i) $728 million ($560 million USD) related to the first instalment of convertible debentures represented by instalment receipts issued in 2015, $1.56 billion ($1.2 billion USD) fixed-to-floating subordinated notes, $500 million in Canadian long-term debt and $4.2 billion ($3.25 billion USD) in US long-term senior unsecured notes; (ii) available cash on hand; and (iii) drawings of $1.4 billion ($1.1 billion USD) on the Company's acquisition credit facility. Total proceeds of the debt, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

On August 2, 2016, the Convertible Debentures Final Instalment Date, Emera obtained the remaining two-thirds of the Convertible Debentures instalment. The net proceeds were $1.4 billion and were used to repay the Company's acquisition credit facility.

For further information on the acquisition of TECO Energy refer to the "Outlook", "Outlook – Emera Florida and New Mexico" and the "Emera Florida and New Mexico" segment section of this MD&A.

Investment in APUC

On May 24, 2016, Emera completed the sale of 19.3 per cent of APUC's issued and outstanding common shares. Proceeds of the sale were used in support of Emera's general financing requirements, including the purchase of TECO Energy. On June 30, 2016, Emera converted 12.9 million subscription receipts and dividend equivalents into 12.9 million APUC common shares. On December 8, 2016, Emera completed the sale of the remaining 12.9 million common shares. Emera no longer holds any interest in APUC.

ECI Amalgamation

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

To effect the amalgamation, all issued and outstanding common shares of ECI were converted to Class A redeemable preferred shares. In Q1 2016, the Class A redeemable preferred shares of ECI not owned were redeemed. Minority ECI shareholders could elect to receive $23.26 ($33.30 Barbadian dollars ("BBD")) in cash per common share ("Cash Offer") or 2.1 Depositary Receipts ("DR") per common share, with each DR representing one quarter of a common share of Emera ("DR Offer"); or a combination of the two offers. The total consideration paid to redeem the minority interest was $15 million ($23 million BBD), consisting of $14 million of the Cash Offer ($22 million BBD) and $1 million of the DR Offer ($1 million BBD). The amalgamated entity retained the name Emera (Caribbean) Incorporated.

Recent Financing Activity

Emera

On December 16, 2016, Emera completed an offering of 6,630,000 common shares, at $45.25 per common share. On December 21, 2016, underwriters fully exercised an over-allotment option of 994,500 common shares, at $45.25 per common share. The aggregate gross and net proceeds from the offering, including the over-allotment, were $345 million and $335 million respectively. The proceeds of the offering were used for general corporate purposes.

On December 13, 2016, Emera's Series H $250 million 2.96% medium-term notes matured and were repaid.

Emera – TECO Energy Acquisition Related Capital Market Transactions

U.S. Notes

On June 16, 2016, Emera US Finance LP, a limited partnership financing subsidiary, wholly owned directly and indirectly by Emera, completed the issuance of $3.25 billion USD senior unsecured notes ("U.S. Notes") by way of private placement. The U.S. Notes were sold only to "qualified institutional buyers" under Rule 144A of the *United States Securities Act of 1933*, as amended (the *"Securities Act"*) and to non-U.S. persons under Regulation S of the *Securities Act* and were not offered for sale in Canada. The U.S. Notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary. The U.S. Notes bear interest semi-annually, in arrears, on June 15 and December 15 of each year, commencing on December 15, 2016. The U.S. Notes will not be listed on a securities exchange.

The U.S. Notes issued are as follows:

- $500 million USD three year, 2.15 per cent Notes due 2019
- $750 million USD five year 2.70 per cent Notes due 2021
- $750 million USD ten year 3.55 per cent Notes due 2026
- $1.25 billion USD thirty year 4.75 per cent Notes due 2046

In connection with the initial issuance of the U.S. Notes, Emera US Finance LP entered into a registration rights agreement with the initial purchasers of the U.S. Notes in which it undertook to offer to exchange the U.S. Notes for new notes, in an equal principal amount and under the same terms, registered under the *Securities Act*. On December 15, 2016, a registration statement on Form F-10/Form S-4 was declared effective by the United States Securities and Exchange Commission (the "SEC"). On January 17, 2017 the new notes were issued.

Hybrid Notes

On June 16, 2016, Emera completed the issuance of $1.2 billion USD unsecured, fixed-to-floating subordinated notes ("Hybrid Notes"). The Hybrid Notes were issued pursuant to a prospectus filed with the Nova Scotia Securities Commission (the "NSSC") and a corresponding registration statement filed with the SEC under the United States/Canada Multijurisdictional Disclosure System. The Hybrid Notes will mature on June 15, 2076. Emera will pay interest on the Hybrid Notes at a fixed rate of 6.75 per cent per year in equal semi-annual instalments on June 15 and December 15 of each year until June 15, 2026. Beginning on June 15, 2026, and on every quarter thereafter that the Hybrid Notes are outstanding until their maturity on June 15, 2076 (the "Interest Reset Date"), the interest rate on the Hybrid Notes will be reset. The Hybrid Notes are not currently listed and Emera does not intend to list them on any securities exchange or include them on any automated quotation system.

Beginning on June 15, 2026, and on every Interest Reset Date until June 15, 2046, the Hybrid Notes will be reset at an interest rate of the three month LIBOR plus 5.44 per cent, payable in arrears. Beginning on June 15, 2046, and on every Interest Reset Date until June 15, 2076, the Hybrid Notes will be reset at an interest rate of the three-month LIBOR plus 6.19 per cent, payable in arrears.

Emera may elect, at its sole option, to defer the interest payable on the Hybrid Notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after June 15, 2026, Emera may, at its option, redeem the Hybrid Notes, at a redemption price equal to 100 per cent of the principal amount, together with accrued and unpaid interest.

Canadian Notes

On June 16, 2016, Emera completed the issuance of $500 million senior unsecured notes ("Canadian Notes"). The Canadian Notes were issued with a seven-year term to maturity and bear interest at a rate of 2.90 per cent. The notes will bear interest semi-annually in arrears on June 16 and December 16 of each year, commencing on December 16, 2016. The Canadian Notes will not be listed on a securities exchange.

The proceeds of the U.S. Notes, Hybrid Notes and Canadian Notes offerings were used to partially finance the purchase price for the Acquisition. Proceeds of the offerings, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

NSPI

On April 28, 2016, NSPI increased its committed syndicated revolving bank line of credit to $600 million from $500 million. The increase will support ongoing business requirements and general corporate purposes.

On May 27, 2016, NSPI increased its commercial paper program to $500 million from $400 million, of which the full amount outstanding is backed by NSPI's operating credit facility referred to above. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

ECI

On November 29, 2016, ECI completed a senior, secured floating rate, non-revolving term loan of $150 million USD. The loan is for a five year term and matures on November 29, 2021. Interest is due semi-annually and is based on 6 month LIBOR plus 4.08 per cent weighted average.

Appointments

Board of Directors
Effective September 1, 2016, John Ramil joined the Emera Board of Directors. Mr. Ramil was President and Chief Executive Officer ("CEO") of TECO Energy until his retirement on August 31, 2016.

Executive
Effective December 1, 2016, Archie Collins was appointed President and Chief Executive Officer of GBPC. Mr. Collins is also Chief Operating Officer of ECI.

Effective November 18, 2016, Scott Balfour was appointed as Chief Operating Officer of Emera. In addition to his responsibilities for Emera's Northeast and Caribbean operations, Mr. Balfour will be responsible for providing senior executive direction for Emera's affiliates in Florida and New Mexico and corporate functions including Human Resources, Stakeholder Relations and Strategic Planning.

Effective September 1, 2016, Rob Bennett was appointed President and Chief Executive Officer of TECO Energy.

Effective September 1, 2016, in addition to his current role of Chief Financial Officer, Emera, Greg Blunden was appointed as TECO Energy's and TEC's Senior Vice President – Finance and Accounting and Chief Financial Officer (Chief Accounting Officer).

Effective September 1, 2016, Sarah MacDonald has been appointed to President of TECO Services Inc., TECO Energy's centralized service company.

Effective August 1, 2016, Bob Hanf was appointed Executive Vice President, Stakeholder Relations and Regulatory Affairs for Emera. Most recently, he was President and CEO of NSPI.

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

Outstanding Common Stock Data

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
December 31, 2014	143.78	$ 2,016
Issuance of common stock	1.25	54
Issued for cash under Purchase Plans at market rate	2.10	88
Discount on shares purchased under Dividend Reinvestment Plan	—	(4)
Options exercised under senior management stock option plan	0.08	2
Employee Share Purchase Plan	—	1
December 31, 2015	147.21	$ 2,157
Conversion of Convertible Debentures (1)	51.99	2,115
Issuance of common stock (2)	7.69	338
Issued for cash under Purchase Plans at market rate	2.51	115
Discount on shares purchased under Dividend Reinvestment Plan	—	(5)
Options exercised under senior management stock option plan	0.62	17
Employee Share Purchase Plan	—	1
December 31, 2016	**210.02**	**$ 4,738**

(1) In 2016, 51.99 million common shares of Emera were issued relating to the conversion of the Convertible Debentures, representing conversion into common shares of 99.6 per cent.
(2) In Q1 2016, Emera issued 0.06 million common shares to facilitate the creation and issuance of 0.2 million depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange. In addition, Emera completed an offering of 7.63 million common shares in December 2016, at $45.25 per common share, for net proceeds of approximately $345 million. The net proceeds were $335 million after $10 million of issuance costs, net of taxes.

As at January 30, 2017 the amount of issued and outstanding common shares was 210.1 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2016 was 204 million (2015 – 147 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2016 was 171 million (2015 – 146 million).

EMERA FLORIDA AND NEW MEXICO

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Florida and New Mexico Net Income

For the	Three months ended December 31	Year ended December 31*
millions of US dollars (except per share amounts)	**2016**	**2016**
Operating revenues – regulated electric	$ 454	$ 1,039
Operating revenues – regulated gas	202	349
Operating revenues – non-regulated	4	7
Total operating revenues	660	1,395
Regulated fuel for generation and purchased power	159	371
Regulated cost of natural gas	80	133
Operating, maintenance and general	176	335
Provincial, state and municipal taxes	45	96
Depreciation and amortization	92	184
Total operating expenses	552	1,119
Income from operations	108	276
Other income (expenses), net	9	17
Interest expense, net	43	87
Income before provision for income taxes	74	206
Income tax expense (recovery)	27	75
Contribution to consolidated net income – USD	$ 47	$ 131
Contribution to consolidated net income – CAD	63	172
Contribution to consolidated earnings per common share – CAD	$ 0.31	$ 1.00
Net income weighted average foreign exchange rate – CAD/USD	$ 1.34	$ 1.31
EBITDA – USD	$ 209	$ 477
EBITDA – CAD	$ 279	$ 629

* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

The Emera Florida and New Mexico USD contribution to consolidated net income was $47 million in Q4 2016. For the year ended December 31, 2016, the Emera Florida and New Mexico USD contribution to consolidated net income was $131 million. This reflects results since July 1, 2016, which is the date of the acquisition by Emera.

The Emera Florida and New Mexico operating unit contribution to consolidated net income for the three months and year ended December 31, 2016 is summarized in the following table:

For the	Three months ended December 31	Year ended December 31*
millions of US dollars	**2016**	**2016**
Tampa Electric	$ 38	$ 126
PGS	9	15
NMGC	10	9
Other [(1)]	(10)	(19)
Contribution to consolidated net income	$ 47	$ 131

* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Other includes TECO Finance and administration costs.

Included below are Emera Florida and New Mexico's Q4 and year ended 2016 results compared to the same period in 2015. Prior year data is for comparison purposes only, as the Emera acquisition was completed on July 1, 2016. The year ended period reflects the six months ended December 31, 2016.

Tampa Electric's net income decreased $5 million to $38 million in Q4 2016 compared to $43 million for the same period in 2015 primarily due to lower energy sales and margin from milder weather in Q4 2016, higher OM&G due to timing and increased depreciation expense resulting from normal additions to facilities to reliably serve customers. For the six-month year ended 2016 period, Tampa Electric's net income increased $1 million to $126 million compared to $125 million in 2015 primarily due to higher energy sales and increased AFUDC on the Polk Power Station expansion project, which were partially offset by higher OM&G due to the same factors as the quarter. The higher energy sales and margin in the six month period were primarily due to the warmer weather in Q3 2016 and 1.6 per cent customer growth.

PGS's net income increased $2 million to $9 million in Q4 2016 compared to $7 million for the same period in 2015 primarily due to higher residential and commercial sales volumes being offset by slightly higher OM&G. PGS had increased energy sales and margin due to 2.7 per cent customer growth, which included higher volume commercial customers. For the six-month year ended 2016 period, PGS's net income increased $2 million to $15 million compared to $13 million in 2015 due to the same factors as the quarter.

NMGC's net income decreased $3 million to $10 million in Q4 2016 compared to $13 million for the same period in 2015 primarily due to lower energy sales from milder weather resulting in lower margin. For the six-month year ended 2016 period, NMGC's net income decreased $1 million to $9 million compared to $10 million in 2015 primarily due to lower margin resulting from the same factors as Q4, which was partially offset by lower interest expense on short-term debt and increased AFUDC related to reliability improvement projects.

Other net loss of $10 million in Q4 2016 and $19 million in the six-month year ended 2016 period was essentially unchanged compared to the same periods in 2015.

The Emera Florida and New Mexico CAD dollar contribution to consolidated net income was $63 million and $172 million for the Q4 2016 and six-month year ended 2016 period, respectively.

Operating Revenues – Regulated

Emera Florida and New Mexico's operating revenues – regulated include sales of electricity, gas and other services as summarized in the following table:

Q4 Operating Revenues – Regulated

millions of US dollars		2016
Electric revenues – regulated (1)	$	454
Gas revenues – regulated (1)		202
Operating revenues – regulated	$	656

(1) Electric and gas regulated revenues include regulatory deferrals related to over-recovery of fuel and clause related costs, if any. Under-recoveries are included in the related expense.

Six-Month Year Ended Operating Revenues – Regulated*

millions of US dollars		2016
Electric revenues – regulated (1)	$	1,039
Gas revenues – regulated (1)		349
Operating revenues – regulated	$	1,388

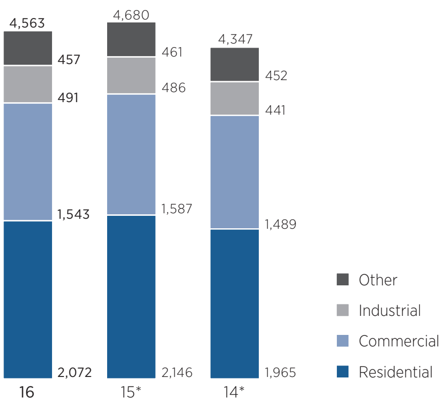
* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Electric and gas regulated revenues include regulatory deferrals related to over recovery of fuel and clause related costs, if any. Under recoveries are included in the related expense.

Electric and Gas Revenues

Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Residential and commercial electricity and gas sales are seasonal. In Florida, Q3 is the strongest period for electricity sales, reflecting warmer weather and cooling demand. In New Mexico and Florida, Q1 is the strongest period for gas sales due to colder weather and heating demand.

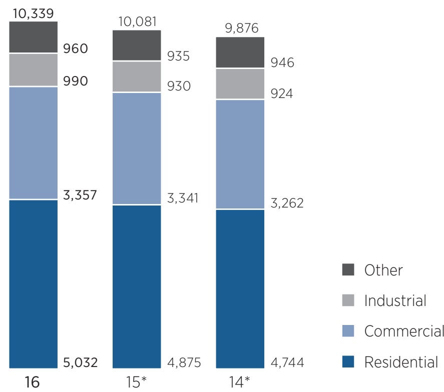
Emera Florida and New Mexico's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. The gas utilities' industrial customers include manufacturing facilities and other large volume operations. Other sales volumes consist primarily of off-system sales to other utilities and revenues from street lighting.

Q4 Electric Sales Volumes
Gigawatt hours (GWh)



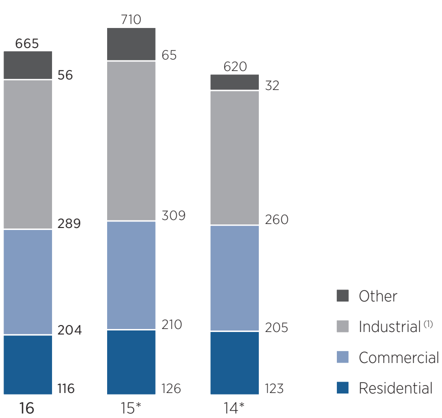
* 2015 and 2014 data is for comparison purposes only.
TECO Energy was acquired on July 1, 2016.

Six-Month Year Ended Electric Sales Volumes
GWh



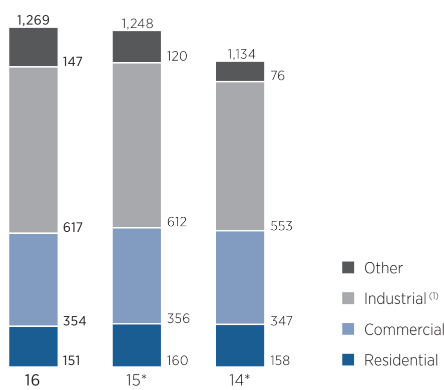
* 2015 and 2014 data is for comparison purposes only.
TECO Energy was acquired on July 1, 2016.

Q4 Gas Sales Volumes
Therms (millions)



* 2015 and 2014 data is for comparison purposes only.
TECO Energy was acquired on July 1, 2016.
(1) Industrial gas sales include on-system power generation customers.

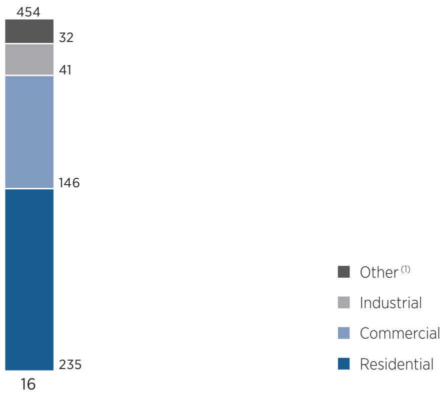
Six-Month Year Ended Gas Sales Volumes
Therms (millions)



* 2015 and 2014 data is for comparison purposes only.
TECO Energy was acquired on July 1, 2016.
(1) Industrial gas sales include on-system power generation customers.

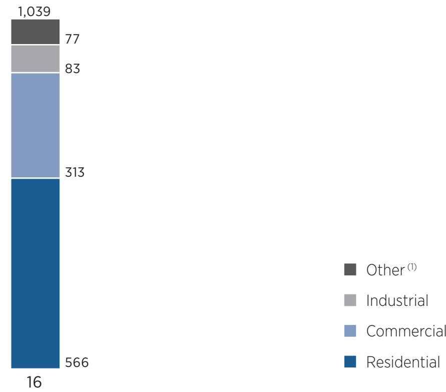
Electric and gas revenues are summarized in the following charts by customer class:

Q4 Electric Revenues
millions of US dollars



(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

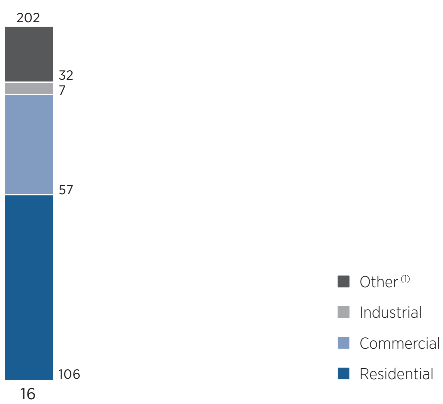
Six-Month Year Ended Electric Revenues*
millions of US dollars



* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

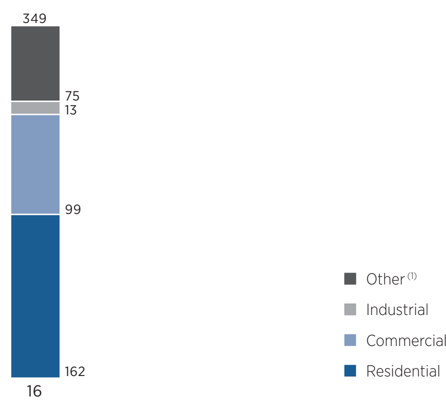
Electric revenues decreased $20 million to $454 million in Q4 2016 compared to $474 million in Q4 2015 primarily due to lower sales volumes from milder weather. For the six-month year ended 2016 period, electric revenues increased $5 million to $1,039 million compared to $1,034 million in the same period in 2015 primarily due to higher sales volumes from warmer weather during the summer months.

Q4 Gas Revenues
millions of US dollars



(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

Six-Month Year Ended Gas Revenues*
millions of US dollars



* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Other includes regulatory deferrals related to over-recovery of clause related costs.

Gas revenues increased $3 million to $202 million in Q4 2016 compared to $199 million in Q4 2015 with consistent revenues by customer class. For the six-month year ended 2016 period, gas revenues increased $19 million to $349 million compared to $330 million in the same period in 2015 primarily due to the increase in off-system sales in Florida.

Regulated Fuel for Generation, Purchased Power and Cost of Natural Gas

Electric Capacity

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is approximately 4,730 MW, which is supplemented by 488 MW contracted with other regulated utilities and independent power producers in Florida. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Tampa Electric's 460 MW Polk Power Station expansion project went into commercial operation on January 16, 2017.

Q4 Production Volumes

GWh	**2016**	2015*	2014*
Natural gas (1)	**1,958**	2,175	1,284
Coal	**1,872**	2,079	2,764
Oil and petcoke	**220**	269	268
Purchased power	**492**	238	29
Total production volumes	**4,542**	4,761	4,345

* 2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.
(1) Natural gas production volumes in 2016 are lower due to outages related to the Polk conversion project.

Six-Month Year Ended Production Volumes

GWh	**2016**	2015*	2014*
Natural gas (1)	**4,451**	5,248	3,507
Coal	**4,281**	4,065	5,719
Oil and petcoke	**516**	533	563
Purchased power	**1,338**	615	275
Total production volumes	**10,586**	10,461	10,064

* 2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016. Year ended data reflects Q3 and Q4 periods.
(1) Natural gas production volumes in 2016 are lower due to outages related to the Polk conversion project.

Q4 Average Fuel Costs/MWh

		2016
Dollars per MWh	**$**	**35**

Six-Month Year Ended Average Fuel Costs/MWh*

		2016
Dollars per MWh	**$**	**35**

* Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

Q4 and year ended average fuel cost per MWh was $35 for both periods in 2016 and 2015. The 2014 average fuel cost per MWh was $42 and $40 for Q4 and the six-month year ended period, respectively. The reduction is primarily due to lower natural gas pricing in 2016 and 2015 compared to 2014.

Tampa Electric's Fuel Costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first (after renewable energy from solar arrays), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

Historically, coal and petcoke have the lowest per unit fuel cost, with natural gas being the next lowest. However, recent declines in natural gas prices and better overall thermal efficiencies have at times resulted in natural gas generation dispatching before coal and petcoke units.

Regulated fuel for generation and purchased power decreased $7 million to $159 million in Q4 2016 compared to $166 million in Q4 2015 primarily due to lower sales volumes, which was partially offset by an increase in purchased power costs to cover outages related to the Polk Power Station expansion project. For the six-month year ended 2016 period, regulated fuel for generation and purchased power increased $3 million to $371 million compared to $368 million for the same 2015 period primarily due to higher sales volumes experienced during the summer months compared to Q3 2015.

Cost of Natural Gas

Emera Florida and New Mexico's gas utilities, PGS and NMGC, purchase gas from various suppliers depending on the needs of its customers. In Florida, the gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has firm transportation capacity for delivery by PGS to its customers. NMGC's service territory is situated between two large natural gas production basins (the San Juan Basin in northwest New Mexico and the Permian Basin located in the southeast New Mexico). Natural gas is transported from these production basins on major interstate pipelines and NMGC's intrastate transmission system to customers using NMGC's distribution system.

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually that elect this option, affording these customers the opportunity to purchase gas from any provider. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net earnings effect when a customer shifts to transportation-only sales.

Gas sales by type are summarized in the following tables:

Q4 Gas Sales Volumes by Type

Therms (millions)	2016	2015*	2014*
System Supply	198	222	185
Transportation	467	488	435
Total	665	710	620

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Six-Month Year Ended Gas Sales Volumes by Type

Therms (millions)	2016	2015*	2014*
System Supply	329	317	271
Transportation	940	931	863
Total	1,269	1,248	1,134

*2015 and 2014 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Gas sales volumes in Q4 2016 were lower than Q4 2015 primarily due to milder weather in New Mexico affecting heating load and lower power generation sales in Florida. For the six-month year ended 2016 period, gas sales volumes increased compared to the same period in 2015 primarily due to customer growth and higher off-system sales in Florida.

Regulatory Recovery Mechanisms

Tampa Electric

Fuel Recovery Clause

Tampa Electric has a fuel recovery clause that is approved by the FPSC, allowing it to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Other Cost Recovery Clauses

The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs including a return on capital invested. Differences between the prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred to a corresponding regulatory asset or liability and recovered from or returned to customers in a subsequent year. In November 2016, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2017.

PGS

Fuel Recovery Clause

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment ("PGA") clause. This clause is designed to recover the costs incurred by PGS 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. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

Other Cost Recovery Clauses

The FPSC annually approves cost-recovery rates for conservation costs including a return on capital invested incurred in developing and implementing energy conservation programs. In 2012, the FPSC approved a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. The FPSC approved PGS' request to accelerate the replacement program of approximately 5 per cent, or 800 kilometres, of the PGS system at a cost of approximately $80 million USD over a 10-year period. As part of the depreciation study settlement agreement approved by the FPSC in February 2017, the Cast Iron/Bare Steel clause was expanded to allow recovery of accelerated replacement of certain obsolete plastic pipe.

NMGC

Fuel Recovery Clause

NMGC recovers gas supply costs through a purchased gas adjustment clause ("PGAC"). This clause recovers NMGC's actual costs 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 can adjust the charges based on next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. In December 2016, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2020.

Electric and Gas Revenue Margin

Emera Florida and New Mexico's utilities distinguish revenues related to various regulated clauses from revenues related primarily to the recovery of non-fuel costs ("base rates"). Electric and gas margin ("margin") and net income are derived primarily by base rates and the return on Florida utility assets associated with approved cost recovery clauses. Fuel and other non-fuel cost recovery clauses do not have a material effect on margin, as substantially all costs are recovered from customers. However the clauses do include a return on capital invested related to these clauses.

Customer classes contribute differently to base rate revenue, with residential and commercial customers contributing more on a dollar per MWh and per therm basis 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.

Regulated operating revenues are shown separately by those recovered through base rates and those recovered by various fuel and non-fuel recovery clauses and are outlined below for the three months ended and six months ended December 31, 2016:

For the			Three months ended December 31
millions of US dollars	**Electric**	**Gas**	**Total**
Electric and gas revenues – base rate	$ 230	$ 106	$ 336
Fuel electric and gas revenues (1)	162	81	243
Other non-fuel cost recovery clause revenues (1)	28	5	33
Other operating revenues	12	5	17
Gross receipts tax and franchise fees revenues (2)	22	5	27
Regulated operating revenues	**$ 454**	**$ 202**	**$ 656**

(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance.
(2) Gross receipts and franchise fees for Tampa Electric and PGS are collected from customers on a dollar-for-dollar basis. As a result, they are included in Regulated revenues and as an offsetting expense in "Provincial, state and municipal taxes" on the Consolidated Statements of Income.

For the			Year ended December 31*
millions of US dollars	**Electric**	**Gas**	**Total**
Electric and gas revenues – base rate	$ 529	$ 184	$ 713
Fuel electric and gas revenues (1)	377	136	513
Other non-fuel cost recovery clause revenues (1)	58	10	68
Other operating revenues	25	9	34
Gross receipts tax and franchise fees revenues (2)	50	10	60
Regulated operating revenues	**$ 1,039**	**$ 349**	**$ 1,388**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance.
(2) Gross receipts and franchise fees for Tampa Electric and PGS are collected from customers on a dollar-for-dollar basis. As a result, they are included in Regulated revenues and as an offsetting expense in "Provincial, state and municipal taxes" on the Consolidated Statements of Income.

Electric margin for the three months and year ended December 31, 2016 is summarized in the following table:

For the	Three months ended December 31	Year ended December 31*
millions of US dollars	**2016**	**2016**
Electric base rate revenue	$ 230	$ 529
Other electric non-fuel cost recovery clause revenues	28	58
Less: Other electric non-fuel clause costs, net of deferrals	(19)	(40)
Electric fuel clause revenue	162	377
Less: Electric fuel clause costs, net of deferrals	(161)	(375)
Electric margin	**$ 240**	**$ 549**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

Electric margin decreased $9 million to $240 million in Q4 2016 compared to $249 million in Q4 2015 primarily due to decreased sales volumes reflecting milder weather. For the six-month year ended 2016 period, electric margin increased $7 million to $549 million compared to $542 million in the same period in 2015 primarily due to the higher energy sales from warmer weather in Q3 2016 that were partially offset by the Q4 2016 items discussed above.

Gas margin for the three months and year ended December 31, 2016 are summarized in the following table:

For the	Three months ended December 31	Year ended December 31*
millions of US dollars	**2016**	**2016**
Gas base rate revenue	$ 106	$ 184
Other gas non-fuel cost recovery clause revenues	5	10
Less: Other gas clause recoverable costs, net of deferrals	(4)	(8)
Gas fuel clause revenue	81	136
Less: Gas fuel clause cost, net of deferrals	(80)	(134)
Gas margin	**$ 108**	**$ 188**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.

Gas margin was unchanged in Q4 2016 compared to Q4 2015 as decreases in NMGC gas margin due to milder weather were offset by increases in PGS' margin due to strong customer growth in Florida. For the six-month year ended 2016 period, gas margin increased $3 million to $188 million in 2016 compared to $185 million in 2015 primarily due to customer growth in Florida, which was partially offset by the milder weather in New Mexico.

Income Taxes

The Florida utilities are subject to corporate income tax at the statutory rate of 39 per cent (combined US federal and Florida state income tax rate). NMGC is subject to corporate income tax at the statutory rate of 39 per cent (combined US federal and New Mexico state income tax rate). Emera Florida and New Mexico's effective tax rate for the three months and six months ended December 31, 2016 was 36 per cent for both periods, which was lower than the statutory rates primarily due to non-taxable AFUDC-equity at Tampa Electric.

Non-GAAP Measure

Electric and Gas Margin Reconciliation

"Electric and gas margin" is a non-GAAP financial measure used to show the amounts that Tampa Electric, PGS and NMGC retain to recover their non-clause costs. Effectively, all prudently incurred clause recoverable costs are recovered through the fuel clauses or various other regulatory clause mechanisms approved by the FPSC and NMPRC. Electric and gas margin associated with non-fuel recovery clauses are essentially the return on assets employed, as all other clause related costs are fully recovered.

The companies' electric and gas margin may not be comparable to other companies' electric or gas margin measures, but in management's view appropriately reflects the utilities' regulatory framework. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric and gas margin was discussed in the Financial Review Electric and Gas Margin section above.

For the			Three months ended December 31, 2016
millions of US dollars	**Electric margin**	**Gas margin**	**Total**
Income from operations	$ 72	$ 36	$ 108
Less:			
Operating revenues – non-regulated	—	4	4
Fuel electric and gas revenues	162	81	243
Other clause revenues	28	5	33
Other operating revenues	12	5	17
Gross receipts tax and franchise fees revenues	22	5	27
Add back:			
Regulated fuel for generation and purchased power	159	—	159
Cost of natural gas sold	—	80	80
Operating, maintenance and general – non-clause related	120	56	176
Provincial, state and municipal taxes	35	10	45
Depreciation and amortization – non-clause related	68	24	92
Non-base rate margin contribution (1)	10	2	12
Electric and gas margin	$ 240	$ 108	**$ 348**

(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance – see electric and gas margin discussion above for details of the contributions.

For the			Year ended December 31, 2016*
millions of US dollars	**Electric margin**	**Gas margin**	**Total**
Income from operations	$ 226	$ 50	$ 276
Less:			
Operating revenues – non-regulated	—	7	7
Fuel electric and gas revenues	377	136	513
Other clause revenues	58	10	68
Other operating revenues	25	9	34
Gross receipts tax and franchise fees revenues	50	10	60
Add back:			
Regulated fuel for generation and purchased power	371	—	371
Cost of natural gas sold	—	133	133
Operating, maintenance and general – non-clause related	231	104	335
Provincial, state and municipal taxes	76	20	96
Depreciation and amortization – non-clause related	135	49	184
Non-base rate margin contribution (1)	20	4	24
Electric and gas margin	$ 549	$ 188	**$ 737**

*Financial results of Emera Florida and New Mexico are from July 1, 2016. For additional information on the acquisition of TECO Energy, refer to the "Developments" section of this MD&A.
(1) Includes return on FPSC approved clause recoverable assets and incentive on generation fleet performance – see electric and gas margin discussion above for details of the contributions.

NSPI

Review of 2016

NSPI Net Income

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated	**$ 352**	$ 338	**$ 1,356**	$ 1,417	$ 1,348
Regulated fuel for generation and purchased power (1)	**136**	133	**490**	543	512
Regulated fuel adjustment mechanism and fixed cost deferrals	**13**	11	**61**	42	47
Operating, maintenance and general	**76**	66	**299**	298	273
Provincial grants and taxes (2)	**10**	9	**39**	38	38
Depreciation and amortization	**49**	52	**197**	206	204
Total operating expenses	**284**	271	**1,086**	1,127	1,074
Income from operations	**68**	67	**270**	290	274
Other expenses, net (3)	**1**	—	**4**	6	5
Interest expense, net	**31**	31	**124**	122	116
Income before provision for income taxes	**36**	36	**142**	162	153
Income tax expense (recovery)	**2**	(7)	**12**	23	20
Net income of Nova Scotia Power Inc.	**34**	43	**130**	139	133
Preferred stock dividends (4)	**—**	3	**—**	9	8
Contribution to consolidated net income	**$ 34**	$ 40	**$ 130**	$ 130	$ 125
Contribution to consolidated earnings per common share	**$ 0.17**	$ 0.27	**$ 0.76**	$ 0.89	$ 0.87
EBITDA	**$ 116**	$ 119	**$ 463**	$ 490	$ 473

(1) Regulated fuel for generation and purchased power includes affiliate transactions and proceeds from the sale of natural gas.
(2) Provincial grants and taxes are included in "Provincial state and municipal taxes" on the Consolidated Statements of Income.
(3) Other expenses, net is included in "Other income (expenses), net" on the Consolidated Statements of Income.
(4) 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.

NSPI's contribution to consolidated net income decreased $6 million to $34 million in Q4 2016 compared to $40 million in Q4 2015. For the year ended December 31, 2016, NSPI's contribution to consolidated net income was consistent with 2015.

Highlights of the changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of Canadian dollars		
Contribution to consolidated net income – 2014		**$ 125**
Increased electric margin primarily due to increased residential load, largely due to weather and a FAM audit disallowance included in 2014		13
Increased fixed cost deferrals primarily due to the new demand side management ("DSM") regulatory deferral commencing in 2015, partially offset by an increase in the amount of non-fuel revenues deferred compared to 2014		31
Increased OM&G primarily due to increased DSM program costs as a result 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		(25)
Increased interest expense, net primarily due to lower interest revenues related to FAM and fixed cost deferrals and higher debt levels		(6)
Increased income tax expense primarily due to increased income before provision for income taxes		(3)
Other		(5)
Contribution to consolidated net income – 2015	**$ 40**	**$ 130**
Increased (decreased) electric margin (see Electric Margin section below for explanation)	5	(18)
Decreased fixed cost deferrals primarily due to 2015 DSM regulatory deferral, partially offset by a reduction in the amount of non-fuel revenues deferred	(2)	(10)
Increased OM&G quarter-over-quarter primarily due to higher storm costs and timing of planned plant maintenance, partially offset by lower pension expense; year-over-year primarily due to higher storm costs and investment in cost saving initiatives, partially offset by lower pension expense	(13)	(11)
Decreased DSM program costs	3	10
Decreased depreciation and amortization primarily due to lower regulatory amortization as a result of a deferral from 2012 being fully amortized in 2015, partially offset by increased depreciation associated with increased property, plant and equipment	3	9
Increased income tax expense quarter-over-quarter primarily due to a 2015 legislated change by the Province of Nova Scotia to the deferred tax treatment of the South Canoe and Sable wind farms resulting in prior period deferred income taxes recorded through earnings being recorded as regulatory assets in Q4 2015; year-over-year decrease primarily due to decreased income before provision for income taxes and increased accelerated tax deductions related to property, plant and equipment	(9)	11
Decreased preferred stock dividends due to redemption of the preferred stock in Q4 2015	3	9
Other	4	—
Contribution to consolidated net income – 2016	**$ 34**	**$ 130**

Operating Revenues – Regulated Electric

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

For the		Three months ended December 31		Year ended December 31	
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Electric revenues	**$ 343**	$ 333	**$ 1,327**	$ 1,389	$ 1,319
Other revenues	**9**	5	**29**	28	29
Operating revenues – regulated electric	**$ 352**	$ 338	**$ 1,356**	$ 1,417	$ 1,348

Electric Revenues

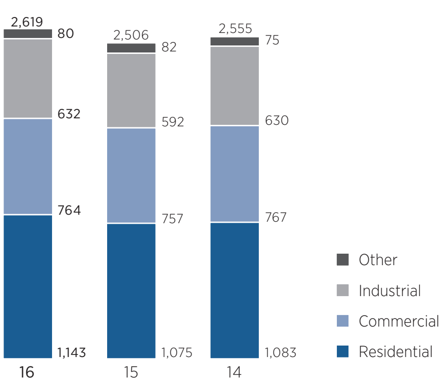
NSPI's electric revenue is affected by rates approved by the UARB and electric sales volumes.

Electric sales volume is primarily driven by general economic conditions, population, weather and DSM activities. Residential and commercial electricity sales are seasonal, with Q1 being the strongest period, reflecting colder weather and fewer daylight hours in the winter season.

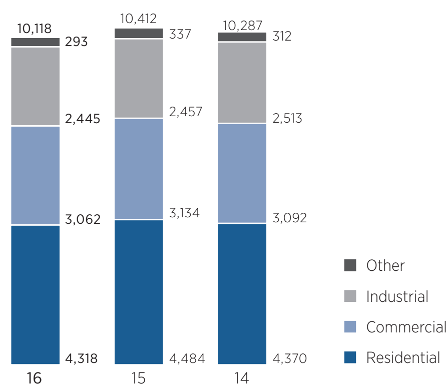
NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations.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

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

Q4 Electric Sales Volumes
Gigawatt hours (GWh)

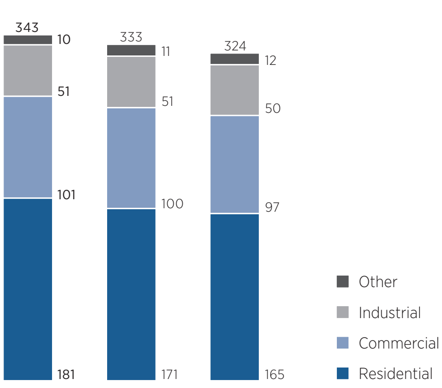


Annual Electric Sales Volumes
GWh

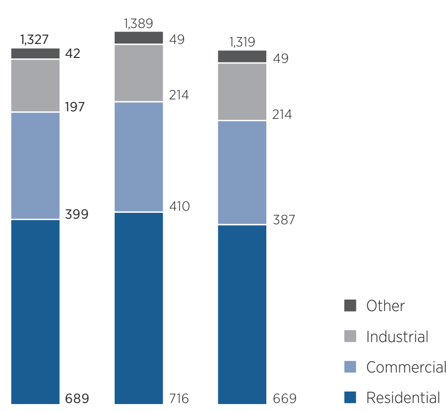


Electric revenues are summarized in the following charts by customer class:

Q4 Electric Revenues
millions of Canadian dollars



Annual Electric Revenues
millions of Canadian dollars



Electric revenues increased $10 million to $343 million in Q4 2016 compared to $333 million in Q4 2015. For the year ended December 31, 2016, electric revenues decreased $62 million to $1,327 million compared to $1,389 million in the same period in 2015. Highlights of the changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of Canadian dollars		
Electric revenues – 2014		**$ 1,319**
Increased fuel related electricity pricing effective January 1, 2015		56
Increased commercial and residential sales volumes primarily due to weather and load growth		20
Decreased industrial sales volume		(5)
Other		(1)
Electric revenues – 2015	**$ 333**	**$ 1,389**
Decreased fuel related electricity pricing effective January 1, 2016	(3)	(12)
Increased residential sales volume quarter-over-quarter primarily due to favourable weather increasing load; decreased residential sales volume year-over-year primarily due to unfavourable weather in Q1	11	(21)
Increased (decreased) commercial sales volume	2	(6)
Increased (decreased) industrial sales volume	2	(16)
Other	(2)	(7)
Electric revenues – 2016	**$ 343**	**$ 1,327**

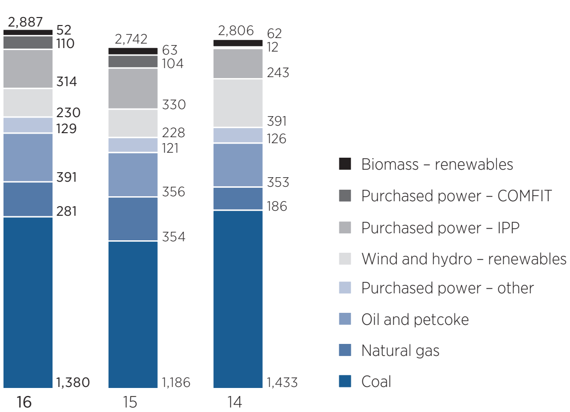
Regulated Fuel for Generation and Purchased Power

Capacity

To ensure reliability of service, NSPI must maintain a generating capacity greater than firm peak demand. The total NSPI-owned generation capacity is 2,487 MW, which is supplemented by 530 MW contracted with IPPs and 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.

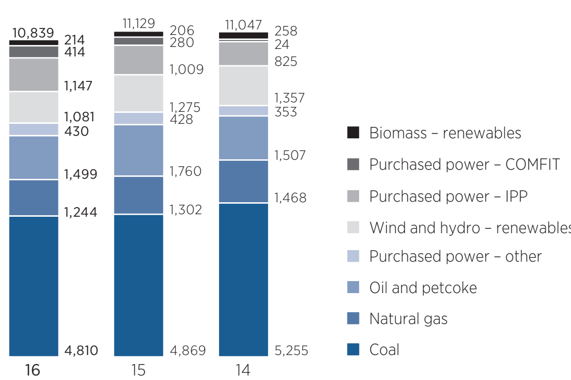
NSPI facilities continue to rank among the best in Canada on performance indicators. The high availability and capability of low cost thermal generating stations provide lower-cost energy to customers. In 2016, thermal plant availability was 86 per cent compared to 88 per cent in 2015. NSPI's four-year average for thermal plant availability is 86 per cent. Availability is in line with industry comparisons. NSPI continues to derive good performance from its thermal plants despite the challenges of increased renewable integration, flexible utilization, and risks associated with an aging fleet.

Q4 Production Volumes
GWh



16	15	14	
706	725	708	Total renewables
2,181	2,017	2,098	Total non-renewables

Annual Production Volumes
GWh



16	15	14	
2,856	2,770	2,464	Total renewables
7,983	8,359	8,583	Total non-renewables

Q4 Average Fuel Costs

		2016		2015		2014
Dollars per megawatt hour (MWh) produced	$	47	$	48	$	45

Annual Average Fuel Costs

		2016		2015		2014
Dollars per MWh produced	$	45	$	49	$	46

Average unit Fuel Costs is consistent in Q4 2016 compared to Q4 2015. Year-over-year, average unit Fuel Costs decreased in 2016 compared to 2015, primarily due to favourable commodity pricing, combined with the transition to economic dispatch of biomass generation compared to must run in 2015. These cost savings are partially offset by increased generation costs associated with the COMFIT program and IPP purchases and decreased NSPI-owned hydro generation.

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 IPPs including COMFIT participants, for which NSPI has power purchase agreements in place. This results in the incremental cost of production generally increasing 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.

NSPI-owned regulated hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, with natural gas being the next lowest. However, declines in natural gas prices and better overall thermal efficiencies have at times resulted in natural gas dispatching before petcoke and coal units. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix is transforming with the addition of new non-dispatchable renewable energy sources such as wind, including IPP and COMFIT, which typically have a higher cost per MWh than NSPI-owned generation or other purchased power sources.

Regulated fuel for generation and purchased power increased $3 million to $136 million in Q4 2016 compared to $133 million in Q4 2015. For the year ended December 31, 2016, regulated fuel for generation and purchased power decreased $53 million to $490 million compared to $543 million in 2015. Highlights of the changes are summarized in the following table:

For the		Three months ended December 31		Year ended December 31
millions of Canadian dollars				
Regulated fuel for generation and purchased power – 2014			**$**	**512**
Decreased commodity prices				(38)
Changes in generation mix and plant performance				51
Increased sales volumes				11
Decreased hydro and NSPI-owned wind production				3
Other				4
Regulated fuel for generation and purchased power – 2015	**$**	**133**	**$**	**543**
Change in commodity prices		1		(47)
Changes in sales volumes		7		(15)
Decrease in hydro production		—		9
Other		(5)		—
Regulated fuel for generation and purchased power – 2016	**$**	**136**	**$**	**490**

Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals

Regulated Fuel Adjustment Mechanism and FAM Regulatory Deferral

NSPI has a Regulated FAM which enables it to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

The FAM is subject to an incentive with NSPI retaining or absorbing 10 per cent of the over or under-recovered Fuel Cost amount to a maximum of $5 million. The incentive was suspended for 2012 through 2015 as a result of UARB approved settlement agreements and is in effect for 2016. The incentive is suspended as part of the *Electricity Plan Act* in 2017 through 2019. For 2016, a FAM incentive of $2.8 million was achieved by NSPI and will be returned to the benefit of customers through a settlement agreement related to the 2014 and 2015 FAM audit, as discussed below.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On August 12, 2016, the FAM audit results relating to the fiscal 2014 and 2015 audit were publically released and recommended one disallowance in the amount of $1 million. This amount related to a specific long-term contract that had also been disallowed following previous FAM audits. On December 21, 2016 the UARB approved a settlement agreement between NSPI and customer representatives which resolved all issues related to the 2014 and 2015 FAM Audit, including all future issues related to the contract that had previously been disallowed. As a result of the settlement agreement, NSPI agreed to forego $3 million of any FAM incentive payment resulting from 2016 Fuel Costs savings it achieved. NSPI achieved a $2.8 million incentive for 2016 and contributed that amount plus an additional $0.2 million to the benefit of customers.

In December 2015, the UARB approved NSPI's 2016 fuel rates and its recovery of prior period unrecovered Fuel Costs. The approved customer rates reset the base cost of fuel rates for 2016. In addition, $12 million was approved to be recovered related to prior years' unrecovered Fuel Costs. This resulted in a combined average rate decrease for customers of approximately 1 per cent in 2016. The rates and recovery of these costs began on January 1, 2016.

The impact of the FAM included in the Consolidated Statements of Income include the effect of Fuel Costs in both the current and preceding years and are detailed below:

- The difference between actual Fuel Costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities" on the Consolidated 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 FAM and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income. Details of the FAM regulatory asset (liability), classified in "Regulatory assets" or "Regulatory liabilities" on the Consolidated Balance Sheets, are summarized in the following table:

millions of Canadian dollars		**2016**		2015
FAM regulatory asset (liability) – Balance as at January 1	**$**	**(28)**	**$**	**48**
(Over) under recovery of current year Fuel Costs		(29)		24
Recovery from customers of prior years' Fuel Costs		(12)		(56)
Excess non-fuel revenues		(5)		(27)
Benefit of tax treatment on South Canoe and Sable wind farms		(15)		(18)
Interest on FAM balance		(5)		1
FAM regulatory asset (liability) – Balance as at December 31	**$**	**(94)**	**$**	**(28)**

As at December 31, 2016, NSPI applied $15 million of the tax benefits associated with the South Canoe and Sable wind projects to the FAM, as directed by the *Electricity Plan Act*. In addition, NSPI will refund $5 million of excess non fuel revenue to customers as part of the one-time credit of approximately $36 million in 2017.

2015 DSM Deferral

Effective January 1, 2015, NSPI must purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The 2015 Program Costs of $35 million were deferred to a regulatory asset and are recoverable from customers over an eight-year period which began in 2016. The UARB directed EfficiencyOne to review the financing options through which EfficiencyOne would borrow the 2015 deferral amount from a commercial lender in order to repay NSPI the amount it expended on behalf of its customers in 2015. On December 2, 2016, EfficiencyOne secured the financing and $31 million was advanced to NSPI to finance the 2015 DSM deferral. As NSPI collects the associated amounts from customers over the next seven years, it will repay the balance to EfficiencyOne. This advance has been set up as a liability in "Other long-term liabilities" with the current portion of the liability included in "Other current liabilities" on the Consolidated Balance Sheets.

In August 2015, the UARB approved a budget for EfficiencyOne of $102 million for the three year period of 2016 through 2018, which will be reduced by $7 million in 2017 as a result of underspend by EfficiencyOne in 2015. The *Electricity Plan Act* has placed a cap of $34 million on 2019 DSM spending.

The DSM regulatory asset includes amounts recognized as DSM and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income.

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

millions of Canadian dollars		**2016**		2015
DSM regulatory asset – Balance as at January 1	**$**	**36**	**$**	**—**
Current period Program Costs deferred		—		35
Recovery of regulatory asset recorded as regulatory amortization		(6)		—
Interest on DSM balance		2		1
DSM regulatory asset – Balance as at December 31	**$**	**32**	**$**	**36**

The DSM regulatory asset is largely offset by a liability of $31 million to EfficiencyOne.

Electric Revenue and Margin

NSPI distinguishes electric revenues related to the recovery of Fuel Costs ("fuel electric revenues") from revenues related to the recovery of non-fuel costs ("non-fuel electric revenues") because the FAM effectively seeks to recover all prudently incurred Fuel Costs. Consequently, Fuel Costs and fuel electric revenues do not have a material effect on NSPI's electric margin or net income, with the exception of the incentive component of the FAM. The incentive component is where NSPI retains or absorbs 10 per cent of the over or under recovered amount to a maximum of $5 million.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to its 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, general economic conditions and DSM have the largest effect on non-fuel electric revenues and electric margin. Changes in industrial load, which are generally due to economic conditions and DSM, have less of an effect on non-fuel electric revenues than would a similar volume change in residential and commercial load.

The addition of new generation facilities to meet legislated greenhouse gas emission reductions and renewable generation requirements and other capital investments are among the drivers increasing NSPI's fixed costs.

Operating revenues are summarized in the following table:

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Fuel electric revenues – current year	**$ 135**	$ 122	**$ 518**	$ 518	$ 512
Fuel electric revenues – recovery of preceding years	**3**	14	**12**	56	–
Non-fuel electric revenues	**205**	197	**797**	815	807
Other revenues	**9**	5	**29**	28	29
Operating revenues	**$ 352**	$ 338	**$ 1,356**	$ 1,417	$ 1,348

Electric margin is summarized in the following table:					
Fuel electric revenues – current year	**$ 135**	$ 122	**$ 518**	$ 518	$ 512
Fuel electric revenues – recovery of preceding years	**3**	14	**12**	56	–
Total fuel electric revenues	**138**	136	**530**	574	512
Regulated fuel for generation and purchased power	**(136)**	(133)	**(490)**	(543)	(512)
Regulated fuel adjustment mechanism	**(5)**	(5)	**(41)**	(32)	(6)
Fuel-related foreign exchange gain (loss) (1)	**–**	2	**1**	1	1
Net fuel revenue (expense) (2)	**(3)**	–	**–**	–	(5)
Non-fuel electric revenues	**205**	197	**797**	815	807
Electric margin	**$ 202**	$ 197	**$ 797**	$ 815	$ 802

(1) As reported in "Other income (expenses), net", on the Consolidated Statements of Income.
(2) The net fuel expense for the three months ended December 31, 2016 is a result of the FAM audit settlement as discussed above.

NSPI's electric margin increased $5 million to $202 million in Q4 2016 compared to $197 million in Q4 2015 primarily due to increased residential sales reflecting colder weather partially offset by NSPI forgoing $3 million of the FAM incentive as a result of the FAM audit settlement agreement. NSPI's electric margin for the year ended December 31, 2016 decreased $18 million to $797 million compared to $815 million in 2015 primarily due to decreased residential and commercial sales reflecting unfavourable weather in Q1 2016.

Q4 Average Electric Margin

	2016	2015	2014
Dollars per MWh	**$ 77**	$ 78	$ 77

Annual Average Electric Margin

	2016	2015	2014
Dollars per MWh	**$ 79**	$ 78	$ 78

NSPI's electric margin per MWh is consistent quarter-over-quarter and year-over-year.

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

In 2016 and 2015, NSPI was subject to corporate income tax at the statutory rate of 31 per cent (combined federal and provincial income tax rate). In 2015, NSPI was subject to Part VI.1 tax relating to preferred stock dividends at the statutory rate of 40 per cent. NSPI also received a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction of 43 per cent of preferred stock dividends.

Non-GAAP Measure

Electric Margin Reconciliation

"Electric margin" is a non-GAAP financial measure used to show the amounts that NSPI retains to recover its non-fuel costs, as effectively all prudently incurred Fuel Costs are recovered through the FAM. NSPI's electric margin may not be comparable to other companies' electric margin measures, but in management's view appropriately reflects NSPI's regulatory framework. This measure is not intended to replace "Income from operations" which, as determined in accordance with USGAAP, is an indicator of operating performance. Electric margin was discussed in the Financial Review Electric Revenue and Margin section above.

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Income from operations	**$ 68**	$ 67	**$ 270**	$ 290	$ 274
Less:					
Fuel electric revenues – current and preceding years	**138**	136	**530**	574	512
FAM audit disallowance	**—**	—	**—**	—	5
Other revenues	**9**	5	**29**	28	29
Add back:					
Regulated fuel for generation and purchased power	**136**	133	**490**	543	512
Operating, maintenance and general	**76**	66	**299**	298	273
Property, state and municipal taxes	**10**	9	**39**	38	38
Depreciation and amortization	**49**	52	**197**	206	204
Regulated fuel adjustment mechanism and fixed cost deferrals	**13**	11	**61**	42	47
Other fuel related costs	**(3)**	—	**—**	—	—
Electric margin	**$ 202**	$ 197	**$ 797**	$ 815	$ 802

EMERA MAINE

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Maine Net Income

For the	Three months ended December 31		Year ended December 31		
millions of US dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated electric	**$ 55**	$ 52	**$ 223**	$ 221	$ 219
Operating revenues – non-regulated	**1**	—	**1**	1	—
Total operating revenues	**56**	52	**224**	222	219
Regulated fuel for generation and purchased power	**6**	7	**28**	29	30
Transmission pool expense [1]	**6**	6	**26**	25	24
Operating, maintenance and general	**12**	14	**51**	49	47
Provincial, state and municipal taxes	**3**	3	**13**	13	11
Depreciation and amortization	**12**	10	**39**	37	43
Total operating expenses	**39**	40	**157**	153	155
Income from operations	**17**	12	**67**	69	64
Other income (expenses), net	**(1)**	(2)	**1**	1	4
Interest expense, net	**3**	3	**14**	13	12
Income before provision for income taxes	**13**	7	**54**	57	56
Income tax expense (recovery)	**4**	3	**18**	21	18
Contribution to consolidated net income – USD	**$ 9**	$ 4	**$ 36**	$ 36	$ 38
Contribution to consolidated net income – CAD	**$ 11**	$ 5	**$ 47**	$ 45	$ 42
Contribution to consolidated earnings per common share – CAD	**$ 0.05**	$ 0.03	**$ 0.27**	$ 0.31	$ 0.29
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.34**	$ 1.33	**$ 1.32**	$ 1.27	$ 1.10
EBITDA – USD	**$ 28**	$ 20	**$ 107**	$ 107	$ 111
EBITDA – CAD	**$ 37**	$ 27	**$ 141**	$ 136	$ 123

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

Emera Maine's USD contribution to consolidated net income increased by $5 million to $9 million in Q4 2016 compared to $4 million in Q4 2015. For the year ended December 31, 2016, Emera Maine's USD contribution to consolidated net income was flat at $36 million compared to $36 million in 2015. Highlights of the USD net income changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of US dollars		
Contribution to consolidated net income – 2014		**$ 38**
(Decreased) increased operating revenues – see Operating Revenues – Regulated Electric section below		3
Increased OM&G primarily due to decreased capitalized construction overheads, partially offset by changes in pension and retiree medical expenses		(2)
Decreased depreciation and amortization due to lower depreciation rates as a result of a 2014 depreciation study and lower regulatory amortization		7
Decreased other income primarily due to AFUDC adjustments recognized as a result of a FERC audit		(4)
Increased income tax expense primarily due to decrease in regulatory amortization and AFUDC adjustments recorded as a result of a FERC audit		(3)
Other		(3)
Contribution to consolidated net income – 2015	**$ 4**	**$ 36**
Increased operating revenues – see Operating Revenues – Regulated Electric section below	3	2
Decreased OM&G quarter-over-quarter primarily due to increased capitalized construction overheads, partially offset by losses recognized on disallowed and abandoned plant. Increased OM&G year-over-year primarily due to increased major storm and regulatory expenses as well as losses recognized on disallowed and abandoned plant, partially offset by increased capitalized construction overheads	2	(2)
Increased income tax expense quarter-over-quarter primarily due to increased income before provision for income taxes, year-over-year decrease primarily due to AFUDC adjustments recorded as a result of a FERC audit in 2015	(1)	3
Other	1	(3)
Contribution to consolidated net income – 2016	**$ 9**	**$ 36**

Emera Maine's CAD contribution to consolidated net income increased by $6 million to $11 million in Q4 2016 from $5 million in Q4 2015. For the year ended December 31, 2016, Emera Maine's CAD contribution to consolidated net income increased by $2 million to $47 million from $45 million in 2015. The foreign exchange rate had no impact for the three months ended December 31, 2016. The impact of a stronger USD increased CAD earnings by $2 million for the year ended December 31, 2016.

Operating Revenues – Regulated Electric

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

Q4 Operating Revenues — Regulated Electric

millions of US dollars		**2016**		2015		2014
Electric revenues	**$**	**40**	$	38	$	41
Transmission pool revenues		**12**		11		11
Resale of purchased power		**3**		3		3
Operating revenues – regulated electric	**$**	**55**	$	52	$	55

Annual Operating Revenues — Regulated Electric

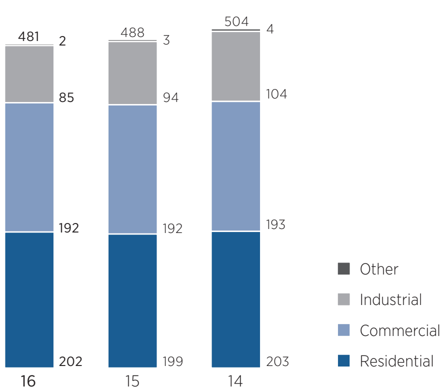
millions of US dollars		**2016**		2015		2014
Electric revenues	**$**	**160**	$	160	$	157
Transmission pool revenues		**51**		49		49
Resale of purchased power		**12**		12		13
Operating revenues – regulated electric	**$**	**223**	$	221	$	219

Electric Revenues

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

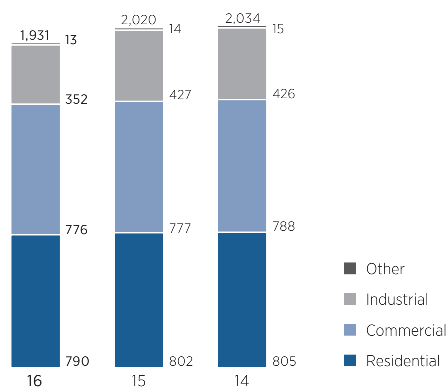
Q4 Electric Sales Volumes

GWh



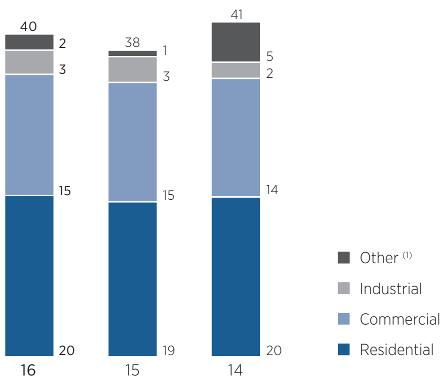
Annual Electric Sales Volumes

GWh



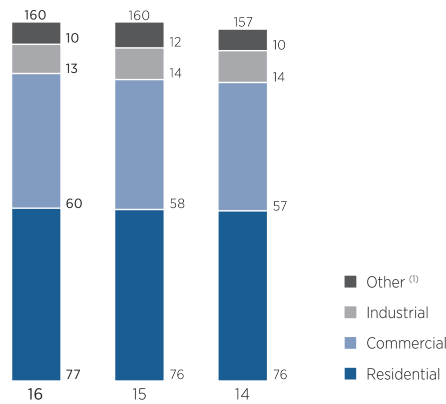
Electric revenues are summarized in the following charts by customer class:

Q4 Electric Revenues
millions of US dollars



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

Annual Electric Revenues
millions of US dollars



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

Electric revenues increased $2 million to $40 million in Q4 2016 compared to $38 million in Q4 2015. For the year ended December 31, 2016, electric revenues were flat at $160 million. Highlights of the changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of US dollars		
Electric revenues – 2014		**$ 157**
Decreased sales volumes primarily due to weather		(1)
Increased primarily due to rate changes		4
Increased due to FERC transmission rate refund		6
Decreased due to transmission revenue adjustments		(6)
Electric revenues – 2015	**$ 38**	**$ 160**
Decreased sales volumes primarily due to loss of load associated with closing two large industrial customers in December 2015 and the impact of weather	(1)	(4)
Increased primarily due to transmission rate changes	1	5
Decreased due to FERC transmission rate refund	(1)	—
Increased (decreased) due to transmission revenue adjustments	3	(1)
Electric revenues – 2016	**$ 40**	**$ 160**

Q4 Electric Revenue/MWh

	2016	2015	2014
Dollars per MWh	**$ 83**	$ 78	$ 81

Annual Average Electric Revenue/MWh

	2016	2015	2014
Dollars per MWh	**$ 83**	$ 79	$ 77

The increase in the average electric revenue per MWh in Q4 2016 compared to Q4 2015 and the year ended 2016 compared to 2015 reflects increased transmission rates offset by transmission revenue adjustments.

Transmission Pool Revenues and Expenses

Transmission pool revenues are recorded in "Operating revenues – regulated electric" and transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

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

For the	Three months ended December 31		Year ended December 31		
millions of US dollars	**2016**	2015	**2016**	2015	2014
Transmission pool revenues	**$ 12**	$ 11	**$ 51**	$ 49	$ 49
Transmission pool expenses	**6**	6	**26**	25	24
Net transmission pool revenues	**$ 6**	$ 5	**$ 25**	$ 24	$ 25

Emera Maine's net transmission pool revenues increased slightly in the quarter and year ended 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 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 was flat at $3 million in Q4 2016 compared to $3 million in Q4 2015, and for the year ended December 31, 2016 at $12 million compared to $12 million in 2015.

Income Taxes

Emera Maine is subject to corporate income tax at the statutory rate of 41 per cent (combined US federal and state income tax rate).

EMERA CARIBBEAN

All amounts are reported in USD, unless otherwise stated.

Review of 2016

Emera Caribbean Net Income

For the	Three months ended December 31		Year ended December 31		
millions of US dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated electric	**$ 78**	$ 84	**$ 316**	$ 346	$ 432
Operating revenues – non-regulated	**—**	—	**—**	6	8
Total operating revenues	**78**	84	**316**	352	440
Regulated fuel for generation and purchased power	**36**	37	**130**	158	248
Non-regulated direct costs	**—**	—	**—**	6	7
Operating, maintenance and general	**24**	24	**89**	102	107
Property taxes (1)	**—**	—	**2**	1	2
Depreciation and amortization	**9**	9	**37**	35	33
Total operating expenses	**69**	70	**258**	302	397
Income from operations	**9**	14	**58**	50	43
Income from equity investment	**—**	1	**2**	2	2
Other income (expenses), net	**1**	2	**47**	5	6
Interest expense, net	**3**	3	**11**	11	11
Income before provision for income taxes	**7**	14	**96**	46	40
Income tax expense (recovery)	**1**	1	**11**	2	3
Net income	**6**	13	**85**	44	37
Non-controlling interest in subsidiaries	**—**	3	**5**	10	8
Preferred stock dividends (2)	**—**	—	**3**	3	3
Contribution to consolidated net income – USD	**$ 6**	$ 10	**$ 77**	$ 31	$ 26
Contribution to consolidated net income – CAD	**$ 8**	$ 14	**$ 100**	$ 41	$ 29
Contribution to consolidated earnings per common share – CAD	**$ 0.04**	$ 0.10	**$ 0.58**	$ 0.28	$ 0.19
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.34**	$ 1.33	**$ 1.31**	$ 1.29	$ 1.10
EBITDA – USD	**$ 19**	$ 26	**$ 144**	$ 92	$ 84
EBITDA – CAD	**$ 25**	$ 34	**$ 189**	$ 118	$ 93

(1) Included in "Provincial, state and municipal taxes" on the Consolidated Statements of Income.
(2) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Consolidated Statements of Income.

Emera Caribbean's USD contribution to consolidated net income decreased by $4 million to $6 million in Q4 2016 compared to $10 million in Q4 2015. For the year ended December 31, 2016, Emera Caribbean's USD contribution to consolidated net income increased by $46 million to $77 million compared to $31 million in 2015. Highlights of the net income changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of US dollars		
Contribution to consolidated net income – 2014		**$ 26**
Increased Electric Margin – see Electric Margin section		4
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		5
Increased non-controlling interest due to increased earnings from ECI, GBPC and Domlec		(2)
Other		(2)
Contribution to consolidated net income – 2015	**$ 10**	**$ 31**
Decreased Electric Margin – see Electric Margin section	(4)	(1)
Decreased OM&G year-over-year primarily due to operational cost savings at GBPC and BLPC	—	13
Increased other income year-over-year primarily due to Q2 pre-tax gain recognized on the BLPC SIF regulatory liability (see details below)	(1)	42
Increased income tax expense year-over-year primarily due to the gain recognized on the BLPC SIF regulatory liability	—	(9)
Other	1	1
Contribution to consolidated net income – 2016	**$ 6**	**$ 77**

In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $22 million USD. As a result, Emera recorded a pre-tax gain of $41 million USD and an after-tax gain of $34 million USD. Absent this gain, the Emera Caribbean contribution to the consolidated net income for the year ended 2016 was $43 million USD ($57 million CAD).

In October 2016, the island of Grand Bahama took a direct hit from Hurricane Matthew. GBPC's generation and substation infrastructure weathered the storm well, however over 2,100 transmission and distribution poles and related conduit were damaged or destroyed, as were many connections to customer homes. Restoration efforts have been completed. Emera Caribbean has recorded $28 million USD of restoration costs associated with Hurricane Matthew with no impact to net income as $21 million USD was recorded as a regulated asset amortized over five years and $7 million USD recorded as property, plant and equipment depreciating at an average 27 years. GBPC's regulator has approved the full recovery of the storm restoration costs in this manner.

Emera Caribbean's CAD contribution to consolidated net income decreased by $6 million to $8 million in Q4 2016 compared to $14 million in Q4 2015. For the year ended December 31, 2016, Emera Caribbean's CAD contribution to consolidated net income increased by $59 million to $100 million in 2016 compared to $41 million in 2015. The foreign exchange rate had no impact for the three months ended 2016. The impact of a stronger USD year-over-year increased CAD earnings by $2 million in 2016 compared to 2015.

Operating Revenues – Regulated Electric

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

Q4 Operating Revenues — Regulated

millions of US dollars	2016	2015	2014
Electric revenues – base rates	$ 42	$ 47	$ 45
Fuel charge	36	36	59
Total electric revenues	78	83	104
Other revenues	—	1	1
Operating revenues – regulated electric	$ 78	$ 84	$ 105

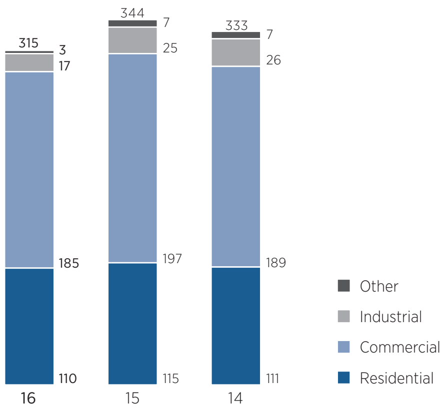
Annual Operating Revenues — Regulated

millions of US dollars	2016	2015	2014
Electric revenues – base rates	$ 185	$ 187	$ 183
Fuel charge	128	155	245
Total electric revenues	313	342	428
Other revenues	3	4	4
Operating revenues – regulated electric	$ 316	$ 346	$ 432

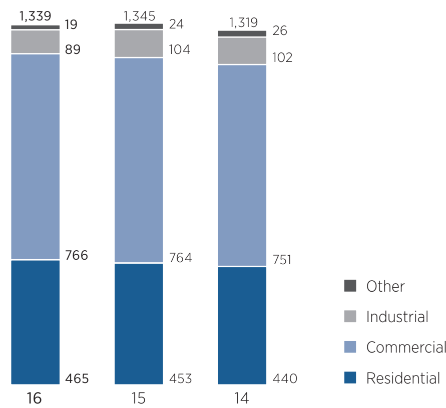
Electric Revenues

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.

Q4 Electric Sales Volumes
GWh



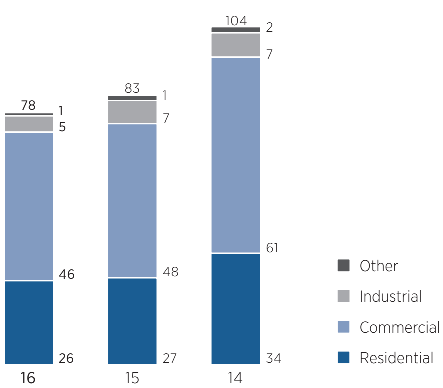
Annual Electric Sales Volumes
GWh



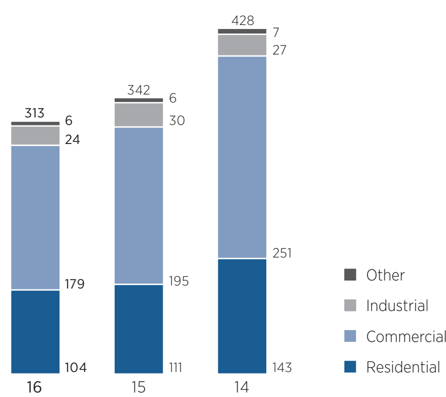
Electric volumes decreased in Q4 2016 compared to Q4 2015 as a result of the direct hit the island of Grand Bahama took from Hurricane Matthew in October 2016. Year-to-date electric volumes remained consistent period over period with the lower Q4 volumes at GBPC being offset by higher volumes at BLPC as a result of warmer weather.

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

Q4 Electric Revenues
millions of US dollars



Annual Electric Revenues
millions of US dollars



Electric revenues decreased $5 million to $78 million in Q4 2016 compared to $83 million in Q4 2015. For the year ended December 31, 2016, electric revenues decreased $29 million to $313 million compared to $342 million in 2015. Highlights of the changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of US dollars		
Electric revenues – 2014		**$ 428**
Decreased fuel charge primarily due to lower fuel prices		(90)
Increased due to higher sales volumes at BLPC and GBPC primarily due to weather		4
Electric revenues – 2015	**$ 83**	**$ 342**
Decreased year-over-year fuel charge primarily due to lower fuel prices	—	(27)
Decreased quarter-over-quarter primarily due to lower sales volumes at GBPC due to the impact of Hurricane Matthew, year-over-year decrease due to lower sales volumes at GBPC due to the impact of Hurricane Matthew partially offset by higher sales volumes at BLPC due to warmer weather	(5)	(2)
Electric revenues – 2016	**$ 78**	**$ 313**

Q4 Average Electric Revenue/MWh

	2016	2015	2014
Dollars per MWh	**$ 248**	$ 241	$ 314

Annual Average Electric Revenue/MWh

	2016	2015	2014
Dollars per MWh	**$ 234**	$ 254	$ 324

The change in average electric revenues per MWh in Q4 2016 compared to Q4 2015 was the result of increased fuel charge at BLPC due to higher fuel prices in the quarter being offset by a decrease in fuel charge at GBPC. The change year-to-date 2016 compared to the same period in 2015 was mainly due to the decrease in fuel prices.

Electric Revenue and Margin

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

Electric margin is summarized in the following table:

For the	Three months ended December 31		Year ended December 31		
millions of US dollars	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated	**$ 78**	$ 84	**$ 316**	$ 346	$ 432
Less: Other revenues	**—**	(1)	**(3)**	(4)	(4)
Total electric revenues	**78**	83	**313**	342	428
Total electric revenues are broken down as follows:					
Electric revenues – base rate	**$ 42**	$ 47	**$ 185**	$ 187	$ 183
Fuel charge	**36**	36	**128**	155	245
Total electric revenues	**78**	83	**313**	342	428
Regulated fuel for generation and purchased power	**36**	37	**130**	158	248
Regulatory amortization [1]	**1**	1	**3**	3	3
Electric margin	**$ 41**	$ 45	**$ 180**	$ 181	$ 177

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

Emera Caribbean's electric margin decreased $4 million to $41 million in Q4 2016 compared to $45 million in Q4 2015 due to lower sales volumes at GBPC due to the direct hit the island of Grand Bahamas took from Hurricane Matthew in October 2016. For the year ended December 31, 2016, electric margin decreased $1 million to $180 million compared to $181 million in 2015 mainly due to lower sales volumes at GBPC due to the impact of Hurricane Matthew, partially offset by higher sales volumes at BLPC due to warmer weather.

Q4 Average Electric Margin/MWh

	2016	2015	2014
Dollars per MWh	**$ 130**	$ 131	$ 132

Annual Average Electric Margin/MWh

	2016	2015	2014
Dollars per MWh	**$ 134**	$ 135	$ 134

Electric margin for the quarter and year-to-date is consistent with prior periods.

Regulated Fuel for Generation and Purchased Power

Q4 Production Volumes

GWh	2016	2015	2014
Oil	**337**	369	349
Hydro	**9**	6	8
Solar	**4**	—	—
Total	**350**	375	357

Annual Production Volumes

GWh	2016	2015	2014
Oil	**1,417**	1,441	1,397
Hydro	**36**	25	31
Solar	**9**	—	—
Total	**1,462**	1,466	1,428

Q4 Average Fuel Costs/MWh

	2016	2015	2014
Dollars per MWh	**$ 103**	$ 99	$ 168

Annual Average Fuel Costs/MWh

	2016	2015	2014
Dollars per MWh	**$ 89**	$ 108	$ 173

The change in average fuel costs in Q4 2016 compared to Q4 2015 and for the year ended December 31, 2016 compared to the same period in 2015 is a result of the change in commodity prices.

Regulated fuel for generation and purchased power decreased $1 million to $36 million in Q4 2016 compared to $37 million in Q4 2015 primarily due to higher commodity prices offset by lower production volumes at GBPC due to Hurricane Matthew. For the year ended December 31, 2016, regulated fuel for generation and purchased power decreased $28 million to $130 million compared to $158 million in 2015 primarily due to lower commodity prices.

Regulatory Recovery Mechanisms

BLPC

BLPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudent fuel costs from customers in a timely manner. The Barbados Fair Trading Commission has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

GBPC

GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudent fuel costs from customers in a timely manner. In December 2016, the GBPA approved holding the all-in (fuel and base) rates consistent with 2016 levels for five years (2017-2021). See the Emera Caribbean Outlook section for additional details.

As a component of its regulatory agreement 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 per cent of amounts below a 7.8 per cent return on rate base and 50 per cent of amounts above 9.8 per cent return on rate base respectively.

Domlec

Substantially all of Domlec fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover prudent fuel costs from customers 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 per cent;
- BLPC is subject to corporate income tax at the statutory rate of 15 per cent;
- GBPC is not subject to corporate income tax;
- Domlec is subject to corporate income tax at the statutory rate of 25 per cent; and
- Lucelec is subject to corporate income tax at the statutory rate of 30 per cent.

Non-GAAP Measure

Electric Margin Reconciliation

"Electric margin" is a non-GAAP financial measure used to show the amounts that BLPC, GBPC and Domlec retain to recover their non-fuel costs, as substantially all prudently incurred fuel costs are recovered from customers.

The companies' electric margin may not be comparable to electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. Management believes measuring electric margin shows the portion of revenues managed through fuel adjustment mechanism, which have a minimal impact on income. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance.

For the	Three months ended December 31		Year ended December 31		
millions of US dollars	**2016**	2015	**2016**	2015	2014
Income from operations	**$ 9**	$ 14	**$ 58**	$ 50	$ 43
Less:					
Operating revenues – non-regulated	**–**	–	**–**	6	8
Other revenue	**–**	1	**3**	4	4
Add back:					
Non-regulated direct costs	**–**	–	**–**	6	7
Operating, maintenance and general	**24**	24	**89**	102	107
Property taxes	**–**	–	**2**	1	2
Depreciation and amortization (1)	**8**	8	**34**	32	30
Electric margin	**$ 41**	$ 45	**$ 180**	$ 181	$ 177

(1) Depreciation and amortization excludes $1 million of regulatory amortization in Q4 2016 (2015 – $1 million) and $3 million for the year ended December 31, 2016 (2015 – $3 million).

EMERA ENERGY

Review of 2016

Emera Energy Adjusted Contribution to Consolidated Net Income

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars (except per share amounts)	**2016**	2015	**2016**	2015	2014
Marketing and trading margin (1)	**$ 23**	$ 38	**$ 58**	$ 85	$ 117
Electricity sales (2)	**109**	143	**460**	546	521
Total operating revenues – non-regulated	**132**	181	**518**	631	638
Non-regulated fuel for generation and purchased power (3)	**84**	87	**334**	335	385
Operating, maintenance and general	**23**	25	**87**	80	79
Provincial, state and municipal taxes	**3**	2	**10**	6	5
Depreciation and amortization	**13**	11	**45**	41	38
Total operating expenses	**123**	125	**476**	462	507
Adjusted income (loss) from operations	**9**	56	**42**	169	131
Income from equity investments (4)	**2**	3	**13**	26	12
Other income (expenses), net	**1**	1	**(1)**	25	3
Interest expense, net	**6**	6	**24**	19	6
Adjusted income (loss) before provision for income taxes	**6**	54	**30**	201	140
Income tax expense (recovery) (5)	**1**	19	**6**	71	42
Adjusted contribution to consolidated net income (loss)	**$ 5**	$ 35	**$ 24**	$ 130	$ 98
After-tax derivative mark-to-market gain (loss)	**$ (36)**	$ 5	**$ (134)**	$ (31)	$ 88
Contribution to consolidated net income	**$ (31)**	$ 40	**$ (110)**	$ 99	$ 186
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.02**	$ 0.24	**$ 0.14**	$ 0.89	$ 0.68
Contribution to consolidated earnings per common share – basic	**$ (0.15)**	$ 0.27	**$ (0.64)**	$ 0.68	$ 1.30
Adjusted EBITDA	**$ 25**	$ 71	**$ 99**	$ 261	$ 184

(1) Marketing and trading margin excludes a pre-tax mark-to-market loss of $64 million in Q4 2016 (2015 – $37 million gain) and a loss of $203 million for the year ended December 31, 2016 (2015 – $2 million loss).
(2) Electricity sales exclude a pre-tax mark-to-market gain (loss) of nil in Q4 2016 (2015 – $22 million loss) and a loss of $7 million for the year ended December 31, 2016 (2015 – $39 million loss).
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $13 million in Q4 2016 (2015 – $5 million loss) and a gain of $18 million for the year ended December 31, 2016 (2015 – $6 million loss).
(4) Income from equity investments excludes a pre-tax mark-to-market loss of $1 million in Q4 2016 (2015 – $10 million loss) and a loss of $1 million for the year ended December 31, 2016 (2015 – $6 million loss).
(5) Income tax expense (recovery) excludes a $16 million recovery relating to mark-to-market losses in Q4 2016 (2015 – $5 million recovery) and $59 million recovery relating to mark-to-market losses for the year ended December 31, 2016 (2015 – $22 million recovery).

Mark-to-Market Adjustments

Emera Energy's "Marketing and trading margin", "Electricity sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by mark-to-market ("MTM") adjustments. The Emera Energy table above shows these amounts net of MTM adjustments and details these adjustments in footnotes to the table. Management believes excluding the effect of MTM valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows. Variance explanations of the MTM charges for this quarter and YTD are explained in the chart below.

Emera Energy has a number of AMAs with counterparties, including local gas distribution utilities, power utilities, and natural gas producers in the northeast. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

Subsequent changes in gas price differentials, to the extent they are not offset by the accounting amortization of the gas transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial during the term of the contract, especially 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 MTM adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM volatility resulting in gains and losses may also increase.

For the quarter, Emera Energy's contribution to consolidated net income decreased by $71 million to a loss of $(31) million in Q4 2016 compared to $40 million in Q4 2015. Adjusted for after-tax derivative mark-to-market and the amortization of transportation capacity, Emera Energy's adjusted contribution to consolidated net income decreased by $30 million to $5 million in Q4 2016 compared to $35 million in Q4 2015.

For the year ended December 31, 2016, Emera Energy's contribution to consolidated net income decreased $209 million to a loss of $(110) million in 2016 compared to $99 million during the same period in 2015. Adjusted for after-tax derivative mark-to-market and the amortization of transportation capacity, Emera Energy's adjusted contribution to consolidated net income decreased by $106 million to $24 million in 2016 compared to $130 million during the same period in 2015.

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2014		**$ 186**
Decreased marketing and trading margin reflects sustained high pricing and volatility in several of Emera Energy's markets in Q1 2014, largely the result of cold weather and a stronger USD in 2015		(32)
Increased electricity sales primarily due to a stronger USD and reduced planned outage work at Bridgeport in 2015, partially offset by lower power prices		25
Decreased non-regulated fuel for generation and purchased power is primarily due to lower commodity fuel prices, partially offset by a stronger USD and reduced planned outage work at Bridgeport in 2015		50
Increased income from equity investments 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		14
Increased other income (expenses) primarily due to a gain on the sale of NWP		22
Increased interest expense, net primarily due to an intercompany loan with Corporate and Other put in place in Q2 2015		(13)
Increased income tax expense primarily due to increased income before provision for income taxes, changes in the proportion of income earned in higher tax rate foreign jurisdiction and a stronger USD		(29)
Decreased mark-to-market, net of tax, primarily due to changes in gas and power contract positions, amortization of transportation assets and the reversal of 2013 mark-to-market losses in 2014		(119)
Other		(5)
Contribution to consolidated net income – 2015	**$ 40**	**$ 99**
Decreased marketing and trading margin – See Marketing and Trading Margin section below	(15)	(27)
Decreased electricity revenues quarter-over-quarter primarily due to lower hedged power prices at the NEGG Facilities, partially offset by higher power prices at Bayside Power. Year-over-year also due to lower market power prices at the NEGG Facilities, partially offset by higher sales volumes as a result of fewer planned outage hours at the Bridgeport Facility in 2016 and a stronger USD	(34)	(86)
Decreased non-regulated fuel for generation and purchased power quarter-over-quarter primarily due to lower hedged commodity prices at the NEGG Facilities, offset by the expiry of a favourable gas contract at Bayside Power in 2016. Year-over-year also offset by the recognition of $20 million in state fuel taxes for 2013 through March 2016, fewer planned outage hours at the Bridgeport Facility in 2016, and a stronger USD	3	1
Decreased income from equity investments – see Equity Investments section below	(1)	(13)
Decreased other income (expenses), net year-over-year primarily due to a one-time gain on the sale of NWP in 2015 and foreign exchange losses in marketing and trading due to the impact of strengthening CAD on CAD liabilities	—	(26)
Decreased income tax expense primarily due to decreased income before provision for income taxes	18	65
Decreased mark-to-market, net of tax quarter-over-quarter primarily due to changes in existing positions on AMA's and amortization of gas transportation assets; year-over-year also due to changes in existing positions on long-term natural gas contracts	(41)	(103)
Other	(1)	(20)
Contribution to consolidated net income – 2016	**$ (31)**	**$ (110)**

A significant portion of Emera Energy earnings are exposed to foreign exchange fluctuations thereby affecting CAD dollar contribution to net earnings. Quarter-over-quarter in 2016 the impact of the USD decreased the loss in CAD dollars by $1 million compared to the same period in 2015. Year-to-date in 2016 the impact of the USD decreased the loss in CAD dollars by $13 million compared to the same period in 2015.

Energy Services

Emera Energy Services ("EES") 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 risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. EES purchases and sells physical natural gas and related transportation capacity rights and provides related energy asset management services. EES is also responsible for commercial management of electricity production and fuel procurement for Emera Energy Generation's fleet. Established in 2002, Emera Energy's marketing and trading business currently has approximately 90 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 US 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 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 for Emera Energy's marketing and trading business is summarized in the following table:

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Marketing and trading margin	**$ 23**	$ 38	**$ 58**	$ 85	$ 117
OM&G	**7**	8	**22**	21	25
Other income (expenses), net	**1**	1	**(3)**	5	3
Adjusted EBITDA	**$ 17**	$ 31	**$ 33**	$ 69	$ 95

Marketing and Trading Margin

Marketing and trading 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 decreased $15 million to $23 million in Q4 2016 compared to $38 million in Q4 2015. Marketing and trading had more transportation capacity in Q4 2015 compared to Q4 2016, and had hedged that Q4 2015 capacity at favourable values.

For the year ended December 31, 2016, marketing and trading margin decreased $27 million to $58 million compared to $85 million in 2015. Higher Q1 2016 margin resulting from a stronger USD and growth in the volume of business was fully offset by the impact of less favourable market conditions and capacity hedges for the remainder of the year.

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 [(2)]	Rhode Island	290	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		1,115			
Maritime Canada					
Bayside	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	Nova Scotia	30	1996	Biomass	Long-term PPA
Total Maritime Canada		320			
Total EEG		1,435			

(1) In Q2 2015, an upgrade at Bridgeport increased its nameplate capacity from 540 MW to 560 MW.
(2) In Q4 2016, an upgrade at Tiverton increased its nameplate capacity from 265 MW to 290 MW.

Emera Energy has approximately 115 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 NEGG 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. Winter and summer are generally the strongest periods, reflecting colder weather and fewer daylight hours in the winter season, and cooling load in the summer.

Emera Energy Generation

Adjusted EBITDA

Adjusted EBITDA is summarized in the following tables:

For the						Three months ended December 31
	New England		Maritime Canada		Total	
millions of Canadian dollars	**2016**	2015	**2016**	2015	**2016**	2015
Energy sales	**$ 70**	$ 111	**$ 29**	$ 20	**$ 99**	$ 131
Capacity and other	**10**	12	**—**	—	**10**	12
Electricity sales	**$ 80**	$ 123	**$ 29**	$ 20	**$ 109**	$ 143
Non-regulated fuel for generation and purchased power	**61**	73	**22**	11	**83**	84
Non-regulated electric margin	**19**	50	**7**	9	**26**	59
Provincial, state and municipal taxes	**3**	1	**1**	—	**4**	1
Operating, maintenance and general	**11**	12	**4**	5	**15**	17
Other income (expenses), net	**1**	—	**—**	—	**1**	—
Adjusted EBITDA	**$ 6**	$ 37	**$ 2**	$ 4	**$ 8**	$ 41

For the									Year ended December 31
	New England			Maritime Canada			Total		
millions of Canadian dollars	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Energy sales	**$ 327**	$ 414	$ 366	**$ 86**	$ 88	$ 109	**$ 413**	$ 502	$ 475
Capacity and other	**47**	44	46	**—**	—	—	**47**	44	46
Electricity sales	**$ 374**	$ 458	$ 412	**$ 86**	$ 88	$ 109	**$ 460**	$ 546	$ 521
Non-regulated fuel for generation and purchased power	**261**	277	312	**65**	52	73	**326**	329	385
Non-regulated electric margin	**113**	181	100	**21**	36	36	**134**	217	136
Provincial, state and municipal taxes	**8**	5	5	**1**	1	1	**9**	6	6
OM&G	**42**	38	30	**21**	18	21	**63**	56	51
Other income (expenses), net	**1**	2	—	**1**	(1)	—	**2**	1	—
Adjusted EBITDA	**$ 64**	$ 140	$ 65	**$ —**	$ 16	$ 14	**$ 64**	$ 156	$ 79

Adjusted EBITDA decreased $33 million to $8 million in Q4 2016 from $41 million in Q4 2015; and year-to-date decreased $92 million to $64 million in 2016 from $156 million for the same period in 2015.

The NEGG Facilities adjusted EBITDA decreased $31 million quarter-over-quarter primarily due to very favourable short-term economic hedges in Q4 2015 compared to Q4 2016 and increased property tax expense at the Bridgeport Facility in Q4 2016. For the year ended December 31, 2016 the NEGG Facilities adjusted EBITDA decreased $76 million. This decrease includes a $20 million charge to cost of fuel to recognize fuel taxes for 2013 through March 2016. Absent this, the NEGG Facilities adjusted EBITDA would have been $84 million, a decrease of $56 million year-over-year. This decrease reflects very favourable short-term economic hedges in 2015, primarily in Q1 and Q4 compared to the same period in 2016, partially offset by the stronger USD and fewer planned outage hours in 2016.

The Maritime Canada Facilities saw an increased cost of gas at Bayside Power, reflecting the expiry of a long-term favourable gas contract, and its replacement at market rates, which was the primary contributor to a $2 million decrease in adjusted EBITDA quarter-over-quarter; and a $16 million decrease year-over-year.

Operating Statistics

For the						Three months ended December 31
	Sales volumes (GWh) (1)		Plant availability (%) (2)		Net capacity factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**1,264**	1,194	**88.8%**	89.5%	**51.7%**	49.7%
Maritime Canada	**420**	417	**85.5%**	95.1%	**61.0%**	60.5%
Total	**1,684**	1,611	**88.1%**	90.8%	**53.8%**	52.1%

For the						Year ended December 31
	Sales volumes (GWh) (1)		Plant availability (%) (2)		Net capacity factor (%) (3)	
	2016	2015	**2016**	2015	**2016**	2015
New England	**5,221**	4,777	**90.9%**	94.5%	**54.3%**	50.5%
Maritime Canada	**1,713**	1,699	**86.7%**	92.7%	**62.4%**	61.9%
Total	**6,934**	6,476	**90.0%**	94.1%	**56.1%**	53.0%

(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.

Sales volumes, plant availability and net capacity factor were consistent quarter-over-quarter. Year-over-year sales volume and net capacity factor increase at the NEGG Facilities was primarily due to fewer planned outage hours in the first half of 2016 and an upgrade at the Bridgeport Energy Facility, completed in Q2 2015. The Maritime Canada Facilities sales volumes and net capacity factor were consistent with the prior year.

The NEGG Facilities sell into price based competitive markets. The primary reason the overall capacity factor is lower as compared to the Maritime Canada Facilities is because the Rumford Plant, in particular, generally operates with a capacity factor of approximately 20 per cent, reflecting current electricity and gas supply price dynamics in its markets.

Equity Investments

Information regarding Emera Energy's equity investment in the Bear Swamp generation facility is summarized below:

Investments in generation facilities	Ownership	Location	Capacity (MW)	Fuel	Description
New England					
Bear Swamp	50 per cent	Massachusetts	600	Hydro	Long-term PPA and selling electricity and capacity to ISO-NE

Adjusted Income From Equity Investments

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

For the		Three months ended December 31				Year ended December 31				
millions of Canadian dollars		**2016**		2015		**2016**		2015		2014
Bear Swamp	**$**	**2**	$	3	**$**	**13**	$	24	$	19
NWP		**—**		—		**—**		2		(7)
Adjusted income from equity investments	**$**	**2**	$	3	**$**	**13**	$	26	$	12

Adjusted Income from equity investments decreased $1 million to $2 million in Q4 2016 compared to $3 million in Q4 2015. For the year ended December 31, 2016, adjusted income from equity investments decreased $13 million to $13 million compared to $26 million in 2015. This is primarily due to a resupply of contracted power sales in Bear Swamp in Q3 2015 that were not delivered in 2014 due to transmission line outages and higher interest costs at Bear Swamp as a result of its Q4 2015 refinancing.

Other Income

On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for $282 million ($223 million USD). This sale resulted in a pre-tax gain of $19 million or $0.13 per common share (after-tax gain of $12 million or $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 to 42 per cent (combined US federal and state income tax rate) on its US sourced income and ranging from 29 to 31 per cent (combined Canadian federal and provincial income tax rate) on its Canada sourced income.

New England Gas Generating Facilities is subject to corporate income tax at the statutory rate ranging from 35 to 41 per cent (combined US federal and state income tax rate).

Brooklyn Energy is subject to corporate income tax at the statutory rate of 31 per cent (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 per cent and $25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $179 million ($137 million USD) non-taxable distribution in Q4 2015.

CORPORATE AND OTHER

Review of 2016

Corporate and Other

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Intercompany revenue [1]	**$ 10**	$ 10	**$ 39**	$ 34	$ 26
Operating revenues – regulated gas	**12**	13	**38**	52	49
Non-regulated operating revenue	**28**	10	**55**	40	49
Non-regulated direct costs	**27**	9	**52**	42	47
Operating, maintenance and general	**9**	33	**133**	105	47
Depreciation and amortization	**1**	1	**4**	2	3
Total operating expenses	**37**	43	**189**	149	97
Income (loss) from operations	**13**	(10)	**(57)**	(23)	27
Income (loss) from equity earnings	**20**	31	**86**	84	65
Other income (expenses), net [2]	**(9)**	(5)	**229**	(4)	4
Interest expense [3]	**76**	35	**328**	71	57
Adjusted income (loss) before provision for income taxes	**(52)**	(19)	**(70)**	(14)	39
Income tax expense (recovery) [4]	**(35)**	(12)	**(100)**	(28)	(12)
Preferred stock dividends	**—**	—	**28**	30	26
Adjusted contribution to consolidated net income	**$ (17)**	$ (7)	**$ 2**	$ (16)	$ 25
After-tax mark-to-market gain (loss)	**2**	100	**(114)**	98	—
Contribution to consolidated net income	**$ (15)**	$ 93	**$ (112)**	$ 82	$ 25
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.08)**	$ (0.05)	**$ 0.01**	$ (0.11)	$ 0.17
Contribution to consolidated earnings per common share – basic	**$ (0.07)**	$ 0.63	**$ (0.65)**	$ 0.56	$ 0.17
Adjusted EBITDA	**$ 25**	$ 17	**$ 262**	$ 59	$ 99

(1) Intercompany revenue consists of interest from EEG.
(2) Other income (expenses) net, excludes a pre-tax mark-to-market gain/loss of nil in Q4 2016 (2015 – $119 million gain) and a loss of $134 million for the year ended December 31, 2016 (2015 – $119 million gain).
(3) Interest expense excludes a pre-tax mark-to-market gain of $2 million in Q4 2016 (2015 – nil) and a gain of $2 million for the year ended December 31, 2016 (2015 – $4 million loss).
(4) Income tax expense (recovery), excludes a nil expense relating to mark-to-market gains in Q4 2016 (2015 – $19 million expense) and an $18 million recovery relating to mark-to-market losses for the year ended December 31, 2016 (2015 – $17 million expense).

Mark-to-Market Adjustments

The after-tax mark-to-market loss of $114 million for the year ended December 31, 2016 (2015 – gain of $98 million) primarily relates to the effect of the Debenture Offering USD-denominated currency revaluation and forward contracts put in place to hedge the proceeds from the final instalment of the Debenture Offering.

"Other income (expenses), net" and "Income tax expense (recovery)" are affected by the mark-to-market adjustments discussed above. Corporate and Other's table above shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

Corporate and Other's contribution to consolidated net income decreased by $108 million to a loss of $(15) million in Q4 2016 compared to earnings of $93 million in Q4 2015. For the year ended December 31, 2016, Corporate and Other's contribution to consolidated net income decreased $194 million to a loss of $(112) million compared to earnings of $82 million in 2015. Highlights of the income changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of Canadian dollars		
Contribution to consolidated net income – 2014		**$ 25**
Increased intercompany revenue due to the issuance of a loan to Emera Energy Generation, partially offset by the repayment of an intercompany loan from Brunswick Pipeline		8
Acquisition costs related to the TECO Energy acquisition		(52)
Decreased OM&G primarily due to lower performance-based compensation and lower business development costs not related to the TECO Energy acquisition		(6)
Income from equity investments – see Income from Equity Investments section below		20
Decreased other income due to the reclassification of APUC subscription receipts, losses incurred in Emera Reinsurance from Tropical Storm Erika and the recognition of NSPML as an equity investment in Q2 2014		(8)
Increased interest expense primarily due to interest on convertible debentures represented by instalment receipts, partially offset by maturity of long-term debt in Q4 2014		(15)
Decreased income tax expense primarily due to decreased income before provision for income taxes		16
Increased preferred stock dividends primarily due to issuance of preferred shares in Q2 2014		(4)
After-tax mark-to-market gain (loss) – see After-Tax Mark-to-Market Gain (Loss) section below		98
Contribution to consolidated net income – 2015	**$ 93**	**$ 82**
Decreased operating revenue – regulated gas primarily as a result of accruing bill credits for NMGC customers as a result of the stipulation agreement on the closing of the TECO Energy acquisition	–	(10)
Increased intercompany revenue due to the issuance of a loan to Emera Energy Generation	–	5
Decreased acquisition costs quarter-over-quarter due to higher TECO Energy acquisition costs in Q4 2015. Increased costs year-over-year due to higher TECO Energy acquisition costs in 2016	20	(37)
Decreased OM&G quarter-over-quarter primarily due to increase in recoveries from affiliates with the addition of Florida and New Mexico; year-over-year includes lower non TECO Energy related business development costs	3	9
Income from equity investments – see Income from Equity Investments section below	(11)	2
Gain on sale of APUC common shares, pre-tax	(12)	160
Gain on conversion of APUC subscription receipts and dividend equivalents into APUC common shares, pre-tax	–	63
Decreased interest expense quarter-over-quarter primarily due to no interest on convertible debentures in Q4 2016 and amortization of the fair market value debt adjustment related to the TECO Energy acquisition. Increased year-over-year also includes Beneficial Conversion Feature recognized on conversion of the Convertible Debentures, higher interest on Convertible Debentures, and interest on bridge facility related to the acquisition of TECO Energy	30	(111)
Post-acquisition interest on financing related to the TECO Energy acquisition, pre-tax	(71)	(146)
Increased income tax recovery primarily due to decreased income before provision for income taxes and deferred income taxes on regulated income recorded as regulatory assets and liabilities; year-over-year increase also due to the non-taxable portion of gains on APUC transactions	23	72
After-tax mark-to-market (loss) – see After-Tax Mark-to-Market Gain (Loss) section below	(98)	(212)
Other	8	11
Contribution to consolidated net income – 2016	**$ (15)**	**$ (112)**

TECO Energy Acquisition Related Costs

Highlights of the TECO Energy related acquisition costs are summarized in the following table:

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Operating revenues – regulated gas	**$ —**	$ —	**$ (10)**	$ —	$ —
Operating, maintenance, and general	**1**	21	**89**	52	—
Interest expense, net	**—**	23	**148**	24	—
Other income (expenses), net	**—**	—	**(3)**	—	—
Income tax expense (recovery)	**(14)**	(14)	**(84)**	(23)	—
Acquisition related costs	**$ (13)**	$ 30	**$ 166**	$ 53	$ —

As part of the acquisition the Company has agreed to fund certain commitments in New Mexico. These commitments include contributions relating to economic development, donations, construction of an enlarged pipeline to the New Mexico/Mexico border, establishment of a matching fund to extend gas infrastructure in New Mexico and an annual customer bill reduction credit through June 30, 2018. For the year ended December 31, 2016, Emera recognized $10 million in "Operating revenues – Regulated gas" and $30 million in "Operating, maintenance, and general" associated with these commitments for a total of $40 million ($23 million after-tax).

In addition to the New Mexico commitments, operating, maintenance, and general expenses includes acquisition related legal, accounting, banking and advisory fees and the accelerated vesting of outstanding stock-based compensation awards. Other income (expenses), net includes foreign exchange gains on acquisition related transactions. Interest expense, net includes interest incurred on the convertible debentures represented by instalment receipts and the acquisition credit facility issued for the purpose of financing the TECO Energy acquisition. In addition, it includes interest for the period between the issuance date and the acquisition date on acquisition-related debt and the Beneficial Conversion Feature discount expensed on conversion of the convertible debentures.

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

The foreign currency earnings impact related to the translation of the TECO Energy acquisition related convertible debenture USD denominated cash balance and the mark-to-market adjustments from forward contracts from economically hedging the Debenture Offering are recorded as a mark-to-market adjustment to net income. Pre-tax losses in 2016 of $134 million for the year ($114 million after-tax loss) are recorded in "Other income (expenses), net" on the Consolidated Statements of Income. These losses offset a pre-tax mark-to-market gain of $119 million ($101 million after-tax gain) recorded in Q4 2015. The after-tax mark-to-market gain (loss) is summarized in the following table:

For the	Three months ended December 31		Year ended December 31		
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
Foreign exchange on TECO Energy acquisition related USD cash	**$ —**	$ 27	**$ (42)**	$ 27	$ —
Mark-to-market adjustment on interest rate hedges in EBP	**2**	—	**2**	(4)	—
Mark-to-market adjustment on USD forward contracts associated with the TECO Energy acquisition	**—**	92	**(92)**	92	—
Income tax expense (recovery)	**—**	(19)	**18**	(17)	—
After-tax mark-to-market gain (loss)	**$ 2**	$ 100	**$ (114)**	$ 98	$ —

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the		Three months ended December 31			Year ended December 31
millions of Canadian dollars	**2016**	2015	**2016**	2015	2014
APUC	**$ —**	$ 18	**$ 18**	$ 37	$ 30
M&NP	**6**	6	**23**	23	18
NSPML	**6**	4	**21**	15	10
LIL	**8**	3	**24**	9	7
Income from equity investments	**$ 20**	$ 31	**$ 86**	$ 84	$ 65

Income from equity investments decreased $11 million to $20 million in Q4 2016 compared to $31 million in Q4 2015. For the year ended December 31, 2016, income from equity investments increased $2 million to $86 million compared to $84 million in 2015. Highlights of the income changes are summarized in the following table:

For the	Three months ended December 31	Year ended December 31
millions of Canadian dollars		
Income from equity investments – 2014		**$ 65**
APUC – 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		7
M&NP		5
NSPML – Due to the recognition of the AFUDC earnings of NSPML as income from equity investment		5
LIL – Increase in investment		2
Income from equity investments – 2015	**$ 31**	**$ 84**
APUC – Due to divestiture of shares	(18)	(19)
NSPML – Increase in equity investment	2	6
LIL – Increase in equity investment	5	15
Income from equity investments – 2016	**$ 20**	**$ 86**

Emera has invested $1.18 billion as at December 31, 2016 of equity, debt and working capital, including $132 million of AFUDC, in the development of the Maritime Link Project. Project to date, Emera has invested $315 million in equity, comprised of $261 million in equity contributed and $54 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The debt has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent. Proceeds from the federally guaranteed debt financing completed in April 2014 will be used to fund project costs until the Project's debt to equity ratio reaches 70 per cent to 30 per cent respectively in Q4 2015. From that point forward, project costs are being funded with debt and equity at a 70 per cent to 30 per cent ratio, with equity contributions of $106 million in 2016.

Emera has invested $400 million in the LIL as at December 31, 2016, which is comprised of $355 million in equity contributed and $45 million of accumulated equity earnings. Equity earnings are recorded based on an annual rate of 8.5 per cent of the equity invested (8.8 per cent prior to July 1, 2016). 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 sufficient cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries maintain solid credit metrics and are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2016 and 2015 include:

Year ended December 31	**2016**	2015	$ Change
millions of Canadian dollars			
Cash and cash equivalents, beginning of period	**$ 1,073**	$ 221	$ 852
Provided by (used in):			
Operating cash flow before changes in working capital	**919**	776	143
Change in working capital	**134**	(102)	236
Operating activities	**1,053**	674	379
Investing activities	**(9,105)**	(124)	(8,981)
Financing activities	**7,448**	221	7,227
Effect of exchange rate changes on cash and cash equivalents	**(65)**	81	(146)
Cash and cash equivalents, end of period	**$ 404**	$ 1,073	$ (669)

Cash Flow from Operating Activities

Refer to Consolidated Income Statement Highlights for details.

Cash Flow Used in Investing Activities

Net cash used in investing activities increased $8,981 million to $9,105 million for the year ended December 31, 2016 compared to $124 million for the year ended December 31, 2015. The increase was primarily due to the acquisition of TECO Energy, proceeds from the sale of NWP in 2015, increased capital spending as a result of the acquisition of TECO Energy and increased investment in NSPML and LIL in 2016. This was partially offset by proceeds from the sale of APUC common shares in 2016.

Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2016 were $1,102 million compared to $436 million in 2015. The increase is a result of the acquisition of TECO Energy, additional capital spending in NSPI and Emera Maine and the investment in a solar facility in Emera Caribbean. Details of the capital spend are shown below:

- $573 million at Emera Florida and New Mexico;
- $309 million at NSPI (2015 – $274 million);
- $86 million at Emera Maine (2015 – $66 million);
- $87 million at Emera Caribbean (2015 – $44 million);
- $39 million at Emera Energy (2015 – $42 million); and
- $8 million at Corporate and Other (2015 – $10 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $7,227 million to $7,448 million for the year ended December 31, 2016 compared to $221 million in December 31, 2015. The increase was primarily due to the proceeds of the long-term debt issuance and convertible debentures related to the acquisition of TECO Energy, proceeds from the long-term debt issuance at ECI, issuance of equity at Emera in Q4 2016 and higher repayment of debt in 2015. This was partially offset by the 2015 proceeds of the long-term debt issuance by Brunswick Pipeline, redemption of NSPI preferred shares in 2015 and increased 2016 dividends on common stock. The majority of the net cash provided by financing activities was used to finance the TECO Energy acquisition.

Working Capital

As at December 31, 2016, Emera's cash and cash equivalents were $404 million (2015 – $1,073 million) and Emera's investment in non-cash working capital was $301 million (2015 – $600 million). Of the $1,073 million of cash and cash equivalents held at December 31, 2015, $728 million was from the proceeds from the convertible debentures for the TECO Energy acquisition and were held in USD. Of the $404 million cash and cash equivalents held at December 31, 2016, $267 million is held by Emera's foreign subsidiaries (2015 – $373 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 predominantly for working capital requirements and capital expenditures in support of growth throughout the businesses, as well as acquisitions, dividends and debt servicing. In addition to using cash generated from operating activities, Emera uses available cash and credit facility borrowings to support normal operations and capital requirements. Emera may reduce short-term borrowings with cash from operations, long-term borrowings, or equity contributions. Emera has credit facilities with varying maturities that cumulatively provide $3.2 billion of credit (see note 24 and note 26 to the 2016 Annual Emera Consolidated Financial Statements for additional information regarding the credit facilities). Emera believes that its liquidity is adequate given its expected operating cash flows, capital expenditures, and related financing plans.

Contractual Obligations

As at December 31, 2016, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2017	2018	2019	2020	2021	Thereafter	Total
Long-term debt	$ 476	$ 791	$ 1,380	$ 835	$ 1,687	$ 9,628	$ 14,797
Purchased power [1]	253	224	206	202	198	2,272	3,355
Fuel and gas supply	475	161	109	28	22	—	795
DSM	42	48	13	—	—	—	103
Pension and post-retirement obligations [2]	133	47	48	49	51	863	1,191
Asset retirement obligations	2	1	1	1	46	396	447
Interest payment obligations [3]	686	641	611	565	515	6,524	9,542
Long-term payable	4	4	4	5	5	9	31
Convertible debentures represented by instalment receipts	—	—	—	—	—	9	9
Transportation [4]	496	392	310	280	196	1,622	3,296
Long-term service agreements [5]	92	55	67	44	42	227	527
Capital projects	133	—	—	—	—	—	133
Equity investment commitments [6]	236	—	—	200	—	—	436
Leases and other [7]	66	17	14	12	8	70	187
	$ 3,094	$ 2,381	$ 2,763	$ 2,221	$ 2,770	$ 21,620	$ 34,849

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(2) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2016. Credited service and earnings are assumed to be crystallized as at December 31, 2016. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over (50 for TECO Energy) as at December 31, 2016 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 December 31, 2016, including any expected required payment under associated swap agreements.
(4) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(5) 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.
(6) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to LIL upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amount as the projects advance through construction.
(7) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

In connection with the acquisition of TECO Energy, Emera made certain commitments approved by the NMPRC. Refer to note 4 of the Company's annual audited financial statements for additional information.

Beginning in 2018, NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over 35 years. The timing and amount of future payments could change based on UARB approval and final costing of the Maritime Link after construction is complete. This transaction will be accounted for as a related party transaction in accordance with the Company's accounting policies. The Company accounts for NSPML as an equity investment.

Forecasted Gross Consolidated Capital Expenditures

2017 forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Total
Generation	$ 153	$ 106	$ —	$ 19	$ 44	$ —	$ 322
New renewable generation	13	—	4	44	2	—	63
Transmission	39	91	45	18	—	—	193
Distribution	233	84	29	52	—	—	398
Gas transmission and distribution	283	—	—	—	—	—	283
Facilities, equipment, vehicles, and other	119	117	14	10	—	13	273
	$ 840	$ 398	$ 92	$ 143	$ 46	$ 13	$ 1,532

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have access to committed syndicated revolving bank lines of credit in either CAD or USD per the table below.

As at December 31, 2016, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Revolving credit facilities	Utilized	Undrawn and available
Emera – Operating and acquisition credit facility	June 2020 – Revolver	$ 700	$ 63	$ 637
Emera Florida and New Mexico – in USD – credit facilities	March 2017 – December 2018	1,300	708	592
NSPI – Operating credit facility	October 2020 – Revolver	600	265	335
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	26	54
Other – in USD – Operating credit facilities	Various	32	9	23

For the purpose of bridge financing for the acquisition of TECO Energy, on September 4, 2015, the Company secured an aggregate of $6.5 billion USD non-revolving term credit facilities ("Acquisition Credit Facilities") from a syndicate of banks. The non-revolving term credit facilities were 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 and on June 16, 2016, Emera further reduced the USD bridge facilities by $4.8 billion. On August 2, 2016, the Convertible Debentures Final Instalment Date, Emera obtained the remaining two-thirds of the Convertible Debentures instalment. The net proceeds were $1.4 billion and were used to fully repay the Company's acquisition credit facility.

Emera's future liquidity and capital needs will be predominantly for working capital requirements and capital expenditures in support of growth throughout the businesses, potential new acquisitions, dividends and debt servicing. These liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets.

Emera and its subsidiaries' recent financing activity is discussed in the Developments section of this MD&A, including the most recent capital markets transactions relating to the TECO Energy Acquisition.

Credit Ratings

Emera and its subsidiaries have been assigned the following senior unsecured debt ratings:

	S&P	Moody's	Fitch	DBRS
Emera Inc.	BBB (Negative)	Baa3 (Stable)	N/A	N/A
TECO Energy/TECO Finance	BBB (Negative)	Baa2 (Stable)	BBB (Stable)	N/A
TEC	BBB+ (Negative)	A3 (Stable)	A- (Stable)	N/A
NMGC	BBB+ (Negative)	N/A	N/A	N/A
NSPI	BBB+ (Negative)	N/A	N/A	A (low) (Stable)

Emera

In June 2016, as a result of the TECO Energy acquisition outlined in the Developments section of this MD&A, Moody's Investor Services assigned the following new credit ratings to Emera:

Issuer	Baa3 (Stable Outlook)
Senior Unsecured	Baa3
Subordinate	Ba2

Emera Florida and New Mexico

On July 6, 2016, Moody's downgraded the credit ratings of TECO Energy and TECO Finance to Baa2 from Baa1 and the issuer rating and senior unsecured ratings of TEC to A3 from A2. Moody's described the ratings outlook for the companies as stable.

On July 1, 2016, following the Merger with Emera, S&P affirmed the issuer credit ratings of TECO Energy and the senior unsecured debt ratings of its subsidiaries, TECO Finance, TEC and NMGC, and maintained the ratings outlook at negative.

On October 9, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy at BBB and TEC at BBB+ and affirmed the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC. Fitch Ratings also described the ratings outlook as stable.

NSPI

On December 13, 2016, DBRS affirmed all ratings on NSPI.

On May 25, 2016, S&P affirmed all ratings on NSPI.

Emera Maine, BLPC, Domlec and GBPC have no public debt, and accordingly have no requirement for public credit ratings. These utilities' credit facilities provide adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, these utilities expect to have sufficient access to competitively priced financing in the unsecured or secured debt markets.

A credit rating is not a recommendation to buy, hold or sell securities and may be subject to revision or withdrawal at any time by the assigned rating agency. Our access to capital markets and cost of financing are influenced by the ratings of our securities. A downgrade, if any, in any rating may affect our ability to borrow and may increase financing costs, which may decrease earnings.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenant is listed below:

	Financial covenant	Requirement	As at December 31, 2016
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.62:1

Share Capital

Emera

As at December 31, 2016, Emera had 210.02 million (2015 – 147.21 million) common shares issued and outstanding. For the year ended December 31, 2016, 10.82 million common shares were issued (2015 – 3.43 million) for net proceeds of $466 million (2015 – $141 million).

On December 16, 2016, Emera completed an offering of 6,630,000 common shares, at $45.25 per common share. On December 21, 2016, underwriters fully exercised an over-allotment option of 994,500 common shares, at $45.25 per common share. The aggregate gross and net proceeds from the offering, including the over-allotment, were $345 million and $335 million, respectively. The proceeds of the offering were used for general corporate purposes.

As at December 31, 2016, Emera had 29 million preferred shares issued and outstanding (2015 – 29 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 2017 for defined benefit pension plans is expected to be $117 million (2016 – $49 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 $27 million for 2017 (2016 – $17 million actual).

Defined Benefit Pension Plan Summary

in millions of Canadian dollars — As at December 31, 2016

Plans by region	TECO Energy Pension Plans	NSPI Pension Plans	Emera Maine Pension Plans	Caribbean Plans	Total
Assets as at December 31, 2016	$ 872	$ 1,161	$ 165	$ 10	$ 2,208
Accounting obligation at December 31, 2016	1,033	1,354	207	13	2,607
Accounting expense during fiscal 2016	$ 12	$ 48	$ 7	$ —	$ 67

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("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, 2016 totalled $753 million (2015 – $765 million). The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. Approximately 80 per cent 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 until that cash is required to service the defeased NSPC debt.

Guarantees and Letters of Credit

Emera had significant guarantees and letters of credit on behalf of third parties outstanding as discussed below. These are not included within the Consolidated Balance Sheets as at December 31, 2016:

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 $1.577 billion, which reduces in the ordinary course as project costs are paid. The current exposure as at December 31, 2016 is $577 million.

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond 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. As a result of the sale in September 2015, the letters of indemnity guaranteed $124 million ($95 million USD).

TECO Energy has remaining letters of indemnity related to TECO Coal, which totalled $80 million ($59 million USD) at December 31, 2016. As of that date Cambrian had posted approximately $54 million ($40 million USD) of additional reclamation bonds to replace corresponding reclamation bonds supported by TECO Energy's indemnity. TECO Energy's indemnity obligations in respect of such bonds will not be released until the applicable State department processes the applicable permit transfers and releases such bonds. 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 to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety.

The amounts outlined above represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies.

The company is working with Cambrian on the process to replace the remaining bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

NSPI has a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2017 and is renewed annually. The amount committed as at December 31, 2016 was $47 million.

Emera has standby letters of credit in the amount of $24 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.

DIVIDEND PAYOUT RATIO

Emera targets a dividend payout ratio of 70 to 75 per cent of adjusted net income. Emera Incorporated's common share dividends paid in 2016 were $1.9950 ($0.4750 in Q1 and Q2 and $0.5225 in Q3 and Q4) per common share and $1.6625 ($0.3875 in Q1, $0.4000 in Q2 and Q3 and $0.4750 in Q4) per common share for 2015, representing a payout ratio of 68.2 per cent of adjusted net income in 2016 and 72.8 per cent for 2015. The decrease in the payout ratio is primarily due to a large increase in adjusted net income in 2016 as a result of the net gain realized on the sale of APUC.

On July 4, 2016, Emera's Board of Directors announced an increase in the annual common share dividend rate from $1.90 to $2.09. The first payment was effective August 15, 2016. Emera also extended its eight per cent annual dividend growth target from 2019 to 2020.

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. In this section, Emera describes these 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. As cost-of-service utilities with an obligation to serve customers, Tampa Electric, PGS, NMGC, 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 as an adjustment 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 (including shifts in policy which could occur as a result of climate change concerns) and changes in governments. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include: NSPML, LIL, M&NP and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate regulated companies and their respective regulators determine whether to allow recovery and to adjust rates based upon the 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 has a 25-year firm service agreement, expiring in 2034, with Repsol Energy Canada ("REC"). This firm service agreement was filed with the NEB, and provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the NEB on a complaint basis. Brunswick Pipeline 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 Brunswick Pipeline may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

Weather and Climate Risk

Shifts in weather patterns affect energy sales and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring service to customers as a result of unplanned outages. Emera responds to outages which occur as a result of significant weather events according to each subsidiary's respective emergency services restoration plan.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters; primarily related to its utility operations. This includes laws setting GHG emissions standards and air emissions standards. Emera is also subject to laws 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. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

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 enforcement of such laws 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.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of achieving full compliance with applicable laws, legislation and company policies and standards. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance with such laws, policies and standards.

Cybersecurity Risk

Emera's reliance on information technology systems and network infrastructure to manage its business, including controls for interconnected systems of generation, distribution and transmission, exposes the Company to potential risks related to cybersecurity attack. Attacks can occur over the Internet, through malware, viruses, attachments to emails, through persons inside of the organization or through persons with access to systems outside of the organization. A cybersecurity attack could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems, or otherwise adversely affect Emera's business and financial results and condition.

Despite security measures in place, the Company's systems, assets and information could experience 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 risks materialize, the Company could suffer costs, losses and damage, all or some of which may not be recoverable through legal, regulatory or other processes. The Company seeks to manage this risk by maintaining a cybersecurity strategy, based on the National Institute of Standards and Technology Cyber Security Framework, to both comply with relevant regulation and sustain industry best-practice governance and capability.

Energy Consumption Risk

Typical of utilities, Emera's rate-regulated subsidiaries are 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 also results 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 how electricity enters the system and how it is bought and sold. 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. The Company's rate-regulated subsidiaries are actively involved in all aspects of customer demand, energy efficiency and government policy to ensure that the impact of these activities benefits customers, are not detrimental to the reliability of the energy service the subsidiary provides, and are accommodated through regulations. Additionally, the Company is monitoring the evolution of distributed generation and technology through its strategic initiatives.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates globally, with an increasing amount of the Company's adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenue 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.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to 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) ("AOCI").

In 2016, approximately 35 per cent of Emera's adjusted net income was derived from subsidiaries with a US dollar functional currency. As such, Emera's earnings are subject to fluctuations in the Canadian dollar to US dollar exchange rate. The operations of TECO Energy are conducted in US dollars, thus Emera's consolidated net income and cash flows are impacted to a greater extent than before the acquisition, by movements in the US dollar relative to the Canadian dollar. The July 1, 2016 acquisition of TECO Energy is expected to increase the percentage of Emera's adjusted net income to approximately 70 per cent going forward. In particular, decreases in the value of the US dollar versus the Canadian dollar could negatively impact the Company's net income as it is reported in Canadian dollars.

Capital Market and Liquidity Risk

Emera's 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. After giving effect to the TECO Energy acquisition, Emera now has total debt of approximately $15 billion. 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.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, and liquidity. A change to a credit rating as a result of changes in any of these items 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.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting 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.

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.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. While regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise 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 investment in the development of the Maritime Link Project has risks commensurate with any large construction project. Risks related to large projects can include, but are not limited to, impact on costs from schedule delays, risk of cost overruns, and ensuring compliance with operating and environmental requirements. Emera deploys robust project and risk management approaches, led by teams with extensive experience in large projects. Specific to the Maritime Link, there are 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.

Emera Energy Marketing and Trading

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 ("VaR") 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 commodities, primarily 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 the 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. The Company takes a strategic approach to hedging the volatility of pricing risk in these markets. When market prices are favourable, the Company will typically enter into hedging instruments that effectively fix the price of natural gas and electricity.

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 65 per cent (55 per cent from the US and 10 per cent from the Caribbean) of Emera's total operating revenues in 2016 (2015 – 45 per cent, with 28 per cent from the US and 17 per cent 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 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. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

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 above 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, with the exception of the TECO Energy Group Retirement Plan. 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, contributions to the plans and the pension and post-retirement liabilities) 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.

Each of Emera's employee defined benefit pension plans are managed according to an approved investment policy and governance framework. Emera employs a long-term approach with respect to asset allocation and each investment policy outlines the level of risk which the Company is prepared to accept with respect to the investment of the pension funds in achieving both the Company's fiduciary and financial objectives. Studies are routinely undertaken every 3 to 5 years with the objective that the plans' asset allocations are appropriate for meeting Emera's long-term pension objectives.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 39 per cent of the full-time and term employees within the Emera labour force are represented by unions.

As at December 31, 2016, approximately 10 per cent 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 labour 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.

Emera manages this risk through regular IT asset lifecycle management, dedicated project teams, executive oversight and appropriate governance structures and strong project management practices. Employees with extensive subject matter expertise assist in planning, project management, implementation and training. Formal back up and critical incident response practices ensure that continuity is maintained in the event of any disruptions or incidents.

Enterprise Resource Planning ("ERP") Implementation Risk

Certain Emera affiliates are in the process of updating their financial information systems through the implementation of an integrated ERP system. There are risks associated with this project, and the Company has adopted a detailed plan to address the risks inherent in the implementation process. The implementation of an ERP system will require the investment of significant financial and human resources. Disruptions, delays or deficiencies in the design and implementation of the new ERP system could affect Emera's ability to monitor its business, pay its suppliers and prepare its financial statements accurately and on a timely basis. Emera manages this risk through a dedicated project team, with executive oversight and a detailed governance structure. Consultants, with extensive ERP expertise, have and will continue to assist in planning, design, project management, implementation and training. The expected implementation date is in late 2017.

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, activities of third parties, damage to facilities and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties and damage to the pipelines facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence. Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could adversely affect the Company's results of operations and cash flows.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax benefits are determined by existing tax laws and could be negatively impacted by changes in 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 the corporate income tax rate. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would also reduce the value of the Company's existing deferred tax assets and could result in a charge to earnings if written down. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

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.

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.

The Company mitigates its uninsured risk by ensuring that insurance limits align with risk exposures, and for uninsured assets and operations, that appropriate risk assessments and mitigation measures are in place. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including uninsured losses.

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 AOCI 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 Tampa Electric, PGS, NMGC, 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 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	**December 31**	December 31
millions of Canadian dollars	**2016**	2015
Derivative instrument assets (current and other assets)	**$ 10**	$ 20
Derivative instrument liabilities (current and long-term liabilities)	**(27)**	(46)
Net derivative instrument assets (liabilities)	**$ (17)**	$ (26)

Hedging Impact Recognized in Net Income

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

For the		Year ended December 31
millions of Canadian dollars	2016	2015
Operating revenues – regulated	$ (12)	$ (9)
Non-regulated fuel for generation and purchased power	2	5
Income from equity investments	(1)	(1)
Effective net gains (losses)	$ (11)	$ (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.

Regulatory Items Recognized on the Balance Sheets

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

As at	December 31	December 31
millions of Canadian dollars	2016	2015
Derivative instrument assets (current and other assets)	$ 229	$ 210
Regulatory assets (current and other assets)	11	64
Derivative instrument liabilities (current and long-term liabilities)	(12)	(64)
Regulatory liabilities (current and long-term liabilities)	(231)	(210)
Net asset (liability)	$ (3)	$ —

Regulatory Impact Recognized in Net Income

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

For the		Year ended December 31
millions of Canadian dollars	2016	2015
Regulated fuel for generation and purchased power [(1)]	$ 2	$ 41
Net gains (losses)	$ 2	$ 41

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

Held-for-trading Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	December 31 2016	December 31 2015
Derivative instruments assets (current and other assets)	$ 37	$ 96
Derivative instruments liabilities (current and long-term liabilities)	(434)	(332)
Net derivative instrument assets (liabilities)	$ (397)	$ (236)

Held-for-trading Items Recognized in Net Income

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

For the millions of Canadian dollars	Year ended December 31 2016	 2015
Non-regulated operating revenues	$ 68	$ 15
Non-regulated fuel for generation and purchased power	(7)	(3)
Other income (expenses), net	(2)	(1)
Net gains (losses)	$ 59	$ 11

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars	December 31 2016	December 31 2015
Derivative instrument assets (current and other assets)	$ –	$ 92
Derivative instrument liabilities (current and long-term liabilities)	(2)	(3)
Net derivative instrument assets (liabilities)	$ (2)	$ 89

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars	Year ended December 31 2016	 2015
Other income (expense)	$ (87)	$ 92
Interest expense, net	2	(3)
Total gains (losses)	$ (85)	$ 89

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 December 31, 2016, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109").

The Chief Executive Officer and 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 as at December 31, 2016.

There have been no changes in Emera or its consolidated subsidiaries' ICFR during the period beginning on January 1, 2016 and ending on December 31, 2016, which have materially affected or are reasonably likely to materially affect ICFR except as outlined below.

Limitation on Scope of Design

NI 52-109 permits a business that the issuer acquires not more than 365 days before the issuer's financial year-end to be excluded from its scope of certifications. The Company has limited the scope of design of DC&P and ICFR to exclude controls, policies and procedures relating to TECO Energy (including its holdings Tampa Electric, PGS and NMGC) which was acquired on July 1, 2016 (refer to note 5 of the Company's annual audited consolidated financial statements for segmented financial information). Tampa Electric Company, an affiliate of TECO Energy, continues to annually evaluate the effectiveness of its DC&P quarterly, and ICFR, in accordance with the *Sarbanes Oxley Act of 2002*.

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 and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), capitalized overhead and valuation of financial instruments. Actual results may differ significantly from these estimates.

Rate Regulation

The rate-regulated accounting policies of Tampa Electric, PGS, NMGC, NSPI, Emera Maine, BLPC, Domlec, GBPC, and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies, which 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. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered.

As required by their respective regulators, Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal as regulatory liabilities. The non-ARO costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment upon retirement. The companies accrue for removal costs over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. The application of regulatory accounting guidance is a critical accounting policy since a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

Emera has recorded $1,322 million (2015 – $699 million) of regulatory assets and $1,639 million (2015 – $465 million) of regulatory liabilities as at December 31, 2016.

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 Company believes that the accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. 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 could change the annual pension funding requirements. This could have a significant impact on the Company's annual cash requirements.

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 per cent 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 8.5 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 and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

	2016		2015	
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Energy Group Retirement Plan	**3.72%**	**7.00%**		
TECO Energy Group Supplemental Executive Retirement Plan	**2.64%**	**N/A**		
TECO Energy Group Benefit Restoration Plan	**3.12%**	**N/A**		
TECO Energy Postretirement Health and Welfare Plan	**3.85%**	**N/A**		
New Mexico Gas Company Retiree Medical Plan	**3.85%**	**5.75%**		
NSPI (1)	**4.00%**	**5.75%**	4.00%	5.75%
Bangor Hydro (2)	**4.25%**	**6.75%**	3.91%	7.50%
MPS (2)	**4.10%**	**6.75%**	3.77%	7.50%
GBPC	**4.75%**	**6.00%**	4.75%	6.00%

(1) Prior to December 31, 2016, the discount rate for NSPI was rounded to the nearest 25 basis points. Effective December 31, 2016 the discount rate for NSPI will be unrounded.
(2) Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged to become Emera Maine.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans is $90 million in 2016. The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions.

The following shows the impact on 2016 benefit cost of a 25 basis point change (0.25 per cent) in the discount rate and asset return assumptions:

	0.25% increase		0.25% decrease	
millions of Canadian dollars	**2016**	2015	**2016**	2015
Discount rate assumption	**$ (7)**	$ (5)	**$ 7**	$ 5
Asset return assumption	**$ (4)**	$ (3)	**$ 4**	$ 3

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 Tampa Electric, PGS, NMGC, Emera Maine, BLPC, GBPC and Domlec. 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 includes 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, 2016, unbilled revenues amount to $270 million (2015 – $144 million) on a base of annual operating revenues of $4,277 million (2015 – $2,789 million).

Property, Plant and Equipment

Property, plant and equipment represents 59 per cent of total assets 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.

Depreciation expense was $560 million for the year ended December 31, 2016 (2015 – $296 million).

Goodwill Impairment Assessments

Goodwill is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Reporting units with similar characteristics are grouped for the purpose of determining impairment, if any, of goodwill. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity bypasses the qualitative assessment, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment. Significant assumptions used in these fair value analyses include discount and growth rates, rate case assumptions, valuation of net operating losses, utility sector market performance and transactions, projected operating and capital cash flows for the relevant business and the fair value of debt. In applying the second step (when required), management must estimate the fair value of specific assets and liabilities of the reporting unit.

At December 31, 2016, the Company had goodwill with a total carrying amount of $6,213 million (December 31, 2015 – $264 million), representing the excess of the acquisition purchase price for TECO Energy, Emera Maine and GBPC over the fair values assigned to individual assets acquired and liabilities assumed. As a result of the acquisition of TECO Energy on July 1, 2016, additional goodwill of $5,771 million was recognized by the Company.

Determining the fair market value of goodwill is susceptible to changes from period to period as assumptions about future cash flows are required. Adverse regulatory actions, such as significant reductions in the allowed ROE at Tampa Electric, PGS, NMGC, Emera Maine or GBPC could negatively impact goodwill in the future. In addition, changes in significant assumptions, including growth rates, utility sector market performance and transactions, projected operating and capital cash flows from the affiliates businesses, could also negatively impact goodwill in the future.

No impairment provisions with respect to goodwill were required for either 2016 or 2015.

Long-Lived Assets Impairment Assessments

In accordance with accounting guidance for long-lived assets, the Company assesses whether there has been an impairment of long-lived assets and certain intangibles held and used when such indicators exist. The Company reviews all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. However, in the case of a triggering event, such as a significant market disruption or sale of a business, the values of related long-lived assets are reviewed.

The Company believes accounting estimates related to asset impairments are critical estimates for the following reasons: 1) the estimates are highly susceptible to change, as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the current market conditions in such periods; 2) markets can experience significant uncertainties; 3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings could be material. The Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

No impairment provisions with respect to long-lived assets were required for either 2016 or 2015.

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.

The Company believes that the accounting estimate related to income taxes is a critical estimate for the following reasons: 1) realization of deferred tax assets is dependent upon the generation of sufficient taxable income, both operating and capital, in future periods; 2) a change in the estimated valuation allowance could have a material impact on reported assets and results of operations; and 3) administrative actions of the tax authorities' changes in tax law or regulation, and the uncertainty associated with the application of tax statutes and regulations could change our estimate of income taxes, including the potential for elimination or reduction of our ability to realize tax benefits and to utilize deferred tax assets.

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. The measurement of the fair value of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with the legally obligated costs. There are also uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations and advances in remediation technologies.

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 dollars)		Expected settlement date (number of years)	
	2016	2015	**2016**	2015	**2016**	2015
Thermal	**4.4 – 5.3%**	5.1 – 5.3%	**$265**	$143	**11 – 27**	17 – 28
Hydro	**5.1 – 5.3%**	5.1 – 5.3%	**128**	128	**14 – 45**	16 – 46
Wind	**5.2%**	5.2%	**27**	27	**12 – 19**	13 – 20
Combustion turbines	**5.1 – 5.3%**	5.1 – 5.3%	**8**	8	**7 – 29**	1 – 30
Transmission and distribution	**4.1 – 5.8%**	4.3 – 5.8%	**13**	22	**1 – 33**	1 – 10
Pipeline	**3.8 – 4.4%**	3.8%	**19**	18	**8 – 17.5**	18.5
			$460	$346		

As at December 31, 2016, the AROs recorded on the balance sheet were $170 million (2015 – $109 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $455 million, which will be incurred between 2017 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Capitalized Overhead

As required by their respective regulators, Tampa Electric, PGS, NMGC, 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, 2016, $111 million of overhead costs (2015 – $72 million) 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 arm's-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, 3 and NAV 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 USGAAP accounting policies that are applicable to, and were adopted by the Company in 2016, with no material impact on its consolidated financial statements, are described as follows:

Consolidation

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities were subject to re-evaluation under the revised consolidation model.

Interest – Imputation of Interest

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. The Company adopted this standard in Q1 2016 and December 31, 2015 balances have been retrospectively restated. This change resulted in $62 million of debt issuance costs, as at December 31, 2015, previously presented as "Other long-term assets", being reclassified as a deduction from the carrying amount of the related long-term debt and "Convertible debentures" on its Consolidated Balance Sheets.

In accordance with ASU 2015-15, *Interest: Imputation of Interest*, the Company continues to present debt issuance costs related to its revolving credit facilities and related instruments in "Other long-term assets" on its Consolidated Balance Sheets.

Compensation – Retirement Benefits

In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates.

Intangibles – Goodwill and Other – Internal-Use Software

In April 2015, the FASB issued ASU 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software licence. If a cloud computing arrangement includes a software licence, the customer would account for the software licence element of the arrangement consistent with the acquisition of other software licences. If a cloud computing arrangement does not include a software licence, the customer would account for the arrangement as a service contract. The guidance does not change USGAAP for a customer's accounting for service contracts.

Inventory – Simplifying the Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, *Inventory – Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. The Company early adopted in 2016, as permitted.

Derivatives and Hedging – Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships

In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships*. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The Company early adopted in 2016, as permitted.

Investments – Equity Method and Joint Ventures

In March 2016, the FASB issued ASU 2016-07, *Investments – Equity Method and Joint Ventures*, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. The Company early adopted in 2016, as permitted.

Compensation – Stock Compensation

In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation* to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, accounting for forfeitures, classification of awards as either equity or liabilities and presentation on the statement of cash flows. The Company early adopted in 2016, as permitted.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or have minimal impact on the consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework, which has been codified as ASC Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect narrow scope improvements and practical expedients. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled to. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018. The Company has implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its consolidated financial statements and disclosures. This includes evaluating the available adoption methods, accounting for contributions in aid of construction and contract acquisition costs, the impact of collectability risk, unique contract characteristics in the Company's non-regulated businesses and disclosure requirements. The Company is also monitoring the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force. The ultimate impact of the adoption of ASC Topic 606, and the method of adoption, has not yet been finalized.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, *Leases*. The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators.

This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows

In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Restricted Cash on the Statement of Cash Flows

In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard will require the Company to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents will no longer be presented in the statement of cash flows. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted and is required to be applied prospectively.

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*. The standard provides guidance to simplify the subsequent measurement of goodwill by eliminating the second step of the quantitative test. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. The guidance is required to be applied prospectively.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015
Operating revenues	$ 1,513	$ 1,387	$ 500	$ 877	$ 732	$ 642	$ 527	$ 888
Net income attributable to common shareholders	70	(95)	208	44	192	35	10	160
Adjusted net income attributable to common shareholders	104	14	237	120	87	23	48	172
Earnings per common share – basic	0.34	(0.52)	1.39	0.30	1.31	0.24	0.07	1.10
Earnings per common share – diluted	0.34	(0.52)	1.38	0.30	1.30	0.24	0.07	1.09
Adjusted earnings per common share – basic	0.51	0.08	1.59	0.81	0.59	0.16	0.33	1.18

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. Historically, 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 usage season. However, with the addition of Emera Florida and New Mexico, the third quarter will provide stronger earnings contributions due to the summer being the heaviest electric consumption season in Florida. As the energy industry is seasonal in nature for companies like Emera, seasonal and other weather patterns, as well as the number and severity of storms, can affect the demand for energy and the cost of service. Quarterly results could be affected by items outlined in the Significant Items section and mark-to-market adjustments.

OPERATING STATISTICS

Five-Year Summary

Year ended December 31	2016	2015	2014	2013	2012
Electric energy sales (GWh)					
Residential	**10,605**	5,740	5,616	5,624	5,372
Commercial	**14,895**	11,154	10,989	7,157	6,175
Industrial	**3,876**	2,984	2,971	3,067	2,679
Other	**1,284**	374	385	358	371
Total electric energy sales	**30,660**	20,252	19,961	16,206	14,597
Sources of energy (GWh)					
Thermal – coal	**9,091**	4,869	5,255	5,489	4,998
– oil and petcoke	**3,393**	3,164	2,938	3,026	2,580
– natural gas	**12,630**	7,782	7,692	3,686	3,726
Biomass	**270**	272	320	167	—
Hydro	**856**	1,041	1,129	1,003	828
Wind	**270**	259	258	261	256
Purchases	**5,641**	4,142	3,693	3,528	3,210
Total generation and purchases	**32,151**	21,529	21,285	17,160	15,598
Losses and internal use	**1,491**	1,277	1,324	954	1,001
Total electric energy sold	**30,660**	20,252	19,961	16,206	14,597
Gas sales (Therms) millions					
Residential	**151**	—	—	—	—
Commercial	**354**	—	—	—	—
Industrial	**617**	—	—	—	—
Other	**147**	—	—	—	—
Total gas sales	**1,269**	—	—	—	—
Gas sales by sales type (Therms)					
System supply	**329**	—	—	—	—
Transportation	**940**	—	—	—	—
Total gas sales by sales type	**1,269**	—	—	—	—
Electric customers					
Residential	**1,404,316**	747,629	742,110	738,444	702,738
Commercial	**156,748**	85,480	82,076	83,612	79,613
Industrial	**6,006**	2,628	2,637	2,711	2,521
Other	**17,886**	9,432	10,421	10,510	20,230
Total electric customers	**1,584,956**	845,169	837,244	835,277	805,102
Gas customers					
Residential	**818,870**	—	—	—	—
Commercial	**75,271**	—	—	—	—
Industrial	**80**	—	—	—	—
Other	**1,693**	—	—	—	—
Total gas customers	**895,914**	—	—	—	—

OPERATING STATISTICS

Five-Year Summary (continued)

Year ended December 31	2016	2015	2014	2013	2012
Capacity					
Emera-owned generating nameplate capacity (MW)					
Coal fired	2,727	1,072	1,072	1,072	1,072
Petcoke fired	408	171	171	171	171
Dual fired	350	350	350	350	350
Gas turbines	4,688	1,819	1,799	1,796	747
Biomass	90	90	90	90	—
Hydroelectric	400	402	402	402	395
Wind turbines	180	82	82	82	82
Diesel	135	241	241	245	231
Solar	10	—	—	—	—
Steam	40	40	40	40	40
Comfit	139	—	—	—	—
Independent power producers	893	593	370	308	300
	10,060	4,860	4,617	4,556	3,388
Total number of employees	7,442	3,454	3,530	3,558	3,374
Km of transmission lines	12,199	7,504	7,215	7,224	6,803
Km of distribution lines	63,865	46,162	44,811	44,771	39,590
Km of Gas mains	36,350	—	—	—	—
Km of Gas service lines	11,265	—	—	—	—

Regulated Electric

	Customers	Employee count	Peak demand (MW)	Energy sales (GWh)	Total assets (billions)	Rate base (billions)	Income (millions)	Allowable ROE 2016	Allowable ROE 2015
Tampa Electric (1)	736,047	2,039	4,131	10,339	$ 9.4	$ 7.8	$ 164	9.25–11.25%	—%
NSPI	510,522	1,819	2,111	10,118	4.8	3.7	130	8.75–9.25%	8.75–9.25%
Emera Maine	156,648	403	387	1,931	1.5	1.0	47	10.5%	10.3%
BLPC (2)	126,372	326	157	944	0.5	0.5	91	10.0%	10.0%
GBPC (2)	19,176	186	67	295	0.4	0.3	20	8.8%	10.0%
Domlec (2)	36,184	198	18	99	0.1	0.1	6	15.0%	15.0%

(1) Financial results of TECO Energy are from July 1, 2016.
(2) These subsidiaries use return on rate base, as opposed to ROE.

Regulated Gas

	Customers	Employee count	Max volume day (MMcf)	Gas sales volume (millions of Therms)	Total assets (billions)	Rate base (billions)	Income (millions)	Allowable ROE 2016	Allowable ROE 2015
PGS (1)	374,076	539	543	918	$ 1.6	$ 1.1	$ 20.0	9.25–11.75%	—%
NMGC (1)	521,838	688	437	351	1.1	0.7	12.0	10.0%	—%

(1) Financial results of TECO Energy are from July 1, 2016.

FIVE-YEAR FINANCIAL SUMMARY

For the year ended December 31	2016	2015	2014	2013	2012
millions of Canadian dollars					
Consolidated Statements of Income					
Operating Revenues	$ 4,277	$ 2,789	$ 2,939	$ 2,230	$ 2,059
Operating expenses					
Regulated fuel for generation and purchased power	1,222	815	844	868	811
Regulated cost of natural gas	177	—	—	—	—
Regulated fuel and fixed cost adjustments	61	42	47	(41)	10
Non-regulated fuel for generation and purchased power	313	336	401	90	44
Non-regulated direct costs	29	19	31	52	57
Operating, maintenance and general	1,137	666	561	505	463
Provincial, state and municipal taxes	195	63	58	51	49
Depreciation and amortization	588	340	329	298	278
Income from operations	555	508	668	407	347
Income from equity investments and Other income (expenses), net	274	249	78	64	53
Interest expense, net	585	212	180	172	167
Income before provision for income taxes	244	545	566	299	233
Income tax expense (recovery)	(22)	93	113	44	(13)
Net income	266	452	453	255	246
Non-controlling interest in subsidiaries	11	25	20	19	14
Net income of Emera Incorporated	255	427	433	236	232
Preferred stock dividends	28	30	26	19	11
Net income attributable to common shareholders	227	397	407	217	221
After-tax mark-to-market gain (loss)	(248)	67	88	(42)	(10)
Adjusted net income attributable to common shareholders	475	330	319	259	231
Adjusted EBITDA	1,744	1,031	946	830	693
Balance Sheet Information					
Current assets (1)	2,511	2,596	1,411	1,152	940
Property, plant and equipment, net of accumulated depreciation	17,290	6,469	5,744	5,446	4,605
Other assets					
Income taxes receivable	48	49	29	28	—
Deferred income taxes (1)	125	32	58	68	29
Derivative instruments	131	168	92	61	23
Pension and post-retirement asset	9	9	6	1	—
Regulatory assets	1,242	605	487	558	376
Net investment in direct financing lease	488	480	484	487	490
Investments subject to significant influence (2)	947	1,145	1,028	739	537
Investment securities	48	116	84	74	142
Goodwill	6,213	264	222	207	194
Other long-term assets	169	106	208	56	200
Total assets	$ 29,221	$ 12,039	$ 9,853	$ 8,877	$ 7,536

FIVE-YEAR FINANCIAL SUMMARY (continued)

For the year ended December 31	2016	2015	2014	2013	2012
millions of Canadian dollars					
Current liabilities	$ 3,724	$ 1,367	$ 1,124	$ 1,530	$ 952
Long-term liabilities					
Long-term debt	14,268	3,735	3,660	3,364	3,257
Deferred income taxes (1)	1,672	762	613	548	312
Convertible debentures (2015 – represented by instalment receipts)	8	681	—	—	—
Derivative instruments	150	96	77	27	22
Regulatory liabilities	1,277	353	159	119	93
Asset retirement obligations	170	109	106	99	95
Pension and post-retirement liabilities	669	303	361	256	506
Other long-term liabilities (2)	467	299	48	37	21
Equity					
Common stock	4,738	2,157	2,016	1,703	1,644
Cumulative preferred stock	709	709	709	514	391
Contributed surplus	75	29	9	4	3
Accumulated other comprehensive income (loss)	106	137	(347)	(430)	(776)
Retained earnings	1,076	1,168	1,012	817	788
Total Emera Incorporated equity	6,704	4,200	3,399	2,608	2,050
Non-controlling interest in subsidiaries	112	134	306	289	228
Total equity	6,816	4,334	3,705	2,897	2,278
Total liabilities and equity	$ 29,221	$ 12,039	$ 9,853	$ 8,877	$ 7,536
Statements of Cash Flow Information					
Cash provided by operating activities	1,053	674	763	564	398
Cash used in investing activities	(9,105)	(124)	(711)	(922)	(919)
Cash provided by (used in) financing activities	7,448	221	58	362	534
Financial ratios ($ per share)					
Earnings per share – basic	$ 1.33	$ 2.72	$ 2.84	$ 1.64	$ 1.77
Adjusted earnings per share – basic	$ 2.77	$ 2.26	$ 2.23	$ 1.96	$ 1.85

(1) Emera early adopted ASU 2015-17, *Income Taxes – Balance Sheet Classification of Deferred Taxes,* which simplifies the presentation of deferred income taxes effective Q4 2015. The December 31, 2014 and 2015 periods have been restated.

(2) 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.

Management Report

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Audit Committee.

February 10, 2017

Christopher Huskilson
President and Chief Executive Officer

Gregory Blunden
Chief Financial Officer

Independent Auditors' Report

To the Shareholders of Emera Incorporated

We have audited the accompanying consolidated financial statements of Emera Incorporated, which comprise the consolidated balance sheets as at December 31, 2016 and 2015, and the consolidated statements of income, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Emera Incorporated as at December 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Halifax, Canada
February 10, 2017

Ernst & Young LLP

Ernst & Young LLP
Chartered Professional Accountants
Licenced Public Accountants

Consolidated Statements of Income

Emera Incorporated

For the	Year ended December 31	
millions of Canadian dollars (except per share amounts)	**2016**	2015
Operating revenues		
Regulated electric	**$ 3,437**	$ 2,141
Regulated gas	**499**	52
Non-regulated	**341**	596
Total operating revenues	**4,277**	2,789
Operating expenses		
Regulated fuel for generation and purchased power	**1,222**	815
Regulated cost of natural gas	**177**	—
Regulated fuel adjustment mechanism and fixed cost deferrals	**61**	42
Non-regulated fuel for generation and purchased power	**313**	336
Non-regulated direct costs	**29**	19
Operating, maintenance and general	**1,137**	666
Provincial, state, and municipal taxes	**195**	63
Depreciation and amortization	**588**	340
Total operating expenses	**3,722**	2,281
Income from operations	**555**	508
Income from equity investments (note 6)	**100**	108
Other income (expenses), net (note 7)	**174**	141
Interest expense, net (note 8)	**585**	212
Income before provision for income taxes	**244**	545
Income tax expense (recovery) (note 9)	**(22)**	93
Net income	**266**	452
Non-controlling interest in subsidiaries	**11**	25
Net income of Emera Incorporated	**255**	427
Preferred stock dividends	**28**	30
Net income attributable to common shareholders	**$ 227**	$ 397
Weighted average shares of common stock outstanding (in millions) (note 11)		
Basic	**171**	146
Diluted	**172**	146
Earnings per common share (note 11)		
Basic	**$ 1.33**	$ 2.72
Diluted	**$ 1.32**	$ 2.71
Dividends per common share declared	**$ 1.9950**	$ 1.6625

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Comprehensive Income

Emera Incorporated

For the		Year ended December 31
millions of Canadian dollars	**2016**	2015
Net income	**$ 266**	$ 452
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**32**	435
Unrealized gains (losses) on net investment hedges (2)	**(49)**	–
Cash flow hedges		
Net derivative gains (losses) (3)	**11**	(34)
Less: reclassification adjustment for losses (gains) included in income (4)	**11**	7
Net effects of cash flow hedges	**22**	(27)
Unrealized gains on available-for-sale investment		
Unrealized gain (loss) arising during the period	**3**	(3)
Less: reclassification adjustment for (gains) recognized in income	**(4)**	–
Net unrealized holding gains (losses)	**(1)**	(3)
Net change in unrecognized pension and post-retirement benefit obligation (5)	**12**	107
Other equity method reclassification adjustment (6)	**(46)**	–
Other comprehensive income (loss) (7)	**(30)**	512
Comprehensive income (loss)	**236**	964
Comprehensive income (loss) attributable to non-controlling interest	**8**	53
Comprehensive Income of Emera Incorporated	**$ 228**	$ 911

The accompanying notes are an integral part of these consolidated financial statements.

1) Net of tax recovery of $3 million (2015 – $7 million tax expense) for the year ended December 31, 2016.
2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.
3) Net of tax expense of nil (2015 – $1 million tax expense) for the year ended December 31, 2016.
4) Net of tax recovery of nil (2015 – $2 million tax recovery) for the year ended December 31, 2016.
5) Net of tax expense of $3 million (2015 – $8 million tax expense) for the year ended December 31, 2016.
6) Net of tax recovery of $9 million (2015 – nil) for the year ended December 31, 2016.
7) Net of tax recovery of $9 million (2015 – $14 million tax expense) for the year ended December 31, 2016.

Consolidated Balance Sheets

Emera Incorporated

As at		December 31
millions of Canadian dollars	**2016**	2015
Assets		
Current assets		
Cash and cash equivalents	**$ 404**	$ 1,073
Restricted cash	**87**	19
Receivables, net (note 13)	**1,014**	578
Income taxes receivable (note 9)	**33**	12
Inventory (note 14)	**472**	314
Derivative instruments (notes 15 and 16)	**145**	250
Regulatory assets (note 17)	**80**	94
Prepayments and other current assets (note 19)	**276**	256
Total current assets	**2,511**	2,596
Property, plant and equipment, net of accumulated depreciation and amortization of $7,787 and $3,737, respectively (note 20)	**17,290**	6,469
Other assets		
Income taxes receivable (note 9)	**48**	49
Deferred income taxes (note 9)	**125**	32
Derivative instruments (notes 15 and 16)	**131**	168
Pension and post-retirement assets (note 21)	**9**	9
Regulatory assets (note 17)	**1,242**	605
Net investment in direct financing lease (note 22)	**488**	480
Investments subject to significant influence (note 6)	**947**	1,145
Investment securities	**48**	116
Goodwill (note 23)	**6,213**	264
Other long-term assets	**169**	106
Total other assets	**9,420**	2,974
Total assets	**$ 29,221**	$ 12,039

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets (continued)

Emera Incorporated

As at		December 31
millions of Canadian dollars	**2016**	2015
Liabilities and Equity		
Current liabilities		
Short-term debt (note 24)	**$ 961**	$ 16
Current portion of long-term debt (note 26)	**476**	274
Accounts payable	**1,242**	394
Income taxes payable (note 9)	**19**	8
Derivative instruments (notes 15 and 16)	**325**	349
Regulatory liabilities (note 17)	**362**	112
Pension and post-retirement liabilities (note 21)	**58**	7
Other current liabilities (note 25)	**281**	207
Total current liabilities	**3,724**	1,367
Long-term liabilities		
Long-term debt (note 26)	**14,268**	3,735
Deferred income taxes (note 9)	**1,672**	762
Convertible debentures (2015 – represented by instalment receipts) (note 10)	**8**	681
Derivative instruments (notes 15 and 16)	**150**	96
Regulatory liabilities (note 17)	**1,277**	353
Asset retirement obligations (note 27)	**170**	109
Pension and post-retirement liabilities (note 21)	**669**	303
Other long-term liabilities (note 6)	**467**	299
Total long-term liabilities	**18,681**	6,338
Commitments and contingencies (note 28)		
Equity		
Common stock (note 10)	**4,738**	2,157
Cumulative preferred stock (note 29)	**709**	709
Contributed surplus	**75**	29
Accumulated other comprehensive income (note 12)	**106**	137
Retained earnings	**1,076**	1,168
Total Emera Incorporated equity	**6,704**	4,200
Non-controlling interest in subsidiaries (note 30)	**112**	134
Total equity	**6,816**	4,334
Total liabilities and equity	**$ 29,221**	$ 12,039

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors

M. Jacqueline Sheppard
Chair of the Board

Christopher G. Huskilson
President and Chief Executive Officer

Consolidated Statements of Cash Flows

Emera Incorporated

For the		Year ended December 31
millions of Canadian dollars	**2016**	2015
Operating activities		
Net income	**$ 266**	$ 452
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**593**	352
Income from equity investments, net of dividends	**(59)**	(34)
Allowance for equity funds used during construction	**(22)**	(2)
Deferred income taxes, net	**(67)**	20
Net change in pension and post-retirement liabilities	**13**	37
Regulated fuel adjustment mechanism and fixed cost deferrals	**63**	39
Net change in fair value of derivative instruments	**258**	96
Net change in regulatory assets and liabilities	**(25)**	(6)
Net change in capitalized transportation capacity	**33**	(133)
Foreign exchange loss (gain)	**43**	(27)
Gain on APUC sale of common shares and conversion of subscription receipts (note 7)	**(223)**	—
Other operating activities, net	**46**	(18)
Changes in non-cash working capital (note 31)	**134**	(102)
Net cash provided by operating activities	**1,053**	674
Investing activities		
Acquisition, net of cash acquired (note 4)	**(8,409)**	—
Additions to property, plant and equipment	**(1,031)**	(427)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(276)**	(136)
Net proceeds on sale of investment subject to significant influence and held-for-trading common shares (note 6)	**665**	282
Proceeds on distribution from investment subject to significant influence (note 6)	**—**	179
Other investing activities	**(54)**	(22)
Net cash used in investing activities	**$ (9,105)**	$ (124)

Consolidated Statements of Cash Flows (continued)

Emera Incorporated

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Financing activities		
Change in short-term debt, net	**$ 118**	$ (262)
Proceeds from long-term debt, net of issuance costs	**6,423**	446
Proceeds from convertible debentures, net of issuance costs (2015 – represented by instalment receipts) (note 10)	**1,413**	681
Retirement of long-term debt	**(273)**	(90)
Net borrowings (repayments) under committed credit facilities	**(315)**	(201)
Issuance of common stock, net of issuance costs	**354**	9
Dividends on common stock	**(221)**	(162)
Dividends on preferred stock	**(28)**	(30)
Dividends paid by subsidiaries to non-controlling interest	**(5)**	(14)
Redemption of preferred shares by subsidiary	**—**	(135)
Other financing activities	**(18)**	(21)
Net cash provided by financing activities	**7,448**	221
Effect of exchange rate changes on cash and cash equivalents	**(65)**	81
Net (decrease) increase in cash and cash equivalents	**(669)**	852
Cash and cash equivalents, beginning of year	**1,073**	221
Cash and cash equivalents, end of year	**$ 404**	$ 1,073
Cash and cash equivalents consists of:		
Cash	**$ 221**	$ 996
Short-term investments	**183**	77
Cash and cash equivalents	**$ 404**	$ 1,073

Supplementary Information to Consolidated Statements of Cash Flows (note 31)

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Equity

Emera Incorporated

millions of Canadian dollars	Common stock	Preferred stock	Contributed surplus	Accumulated other comprehensive income ("AOCI")	Retained earnings	Emera total equity	Non-controlling interest	Total equity
2016								
Balance, December 31, 2015	$ 2,157	$ 709	$ 29	$ 137	$ 1,168	$ 4,200	$ 134	$ 4,334
Net income of Emera Incorporated	–	–	–	–	255	255	11	266
Other comprehensive income (loss), net of tax recovery of $9 million	–	–	–	(27)	–	(27)	(3)	(30)
Issuance of common stock, net of after-tax issuance costs	2,450	–	–	–	–	2,450	–	2,450
Dividends declared on preferred stock (note 29)	–	–	–	–	(28)	(28)	–	(28)
Dividends declared on common stock ($1.9950/share)	–	–	–	–	(324)	(324)	–	(324)
Common stock issued under purchase plan	110	–	–	–	–	110	–	110
Senior management stock options exercised	17	–	(1)	–	–	16	–	16
Stock option expense	–	–	2	–	–	2	–	2
Employee Share Purchase Plan	1	–	–	–	–	1	–	1
Beneficial conversion feature, net of tax (note 8)	–	–	43	–	–	43	–	43
Preferred dividends paid and payable by subsidiaries to non-controlling interests	–	–	–	–	–	–	(3)	(3)
Common dividends paid and payable by subsidiaries to non-controlling interest	–	–	–	–	–	–	(2)	(2)
Acquisition of non-controlling interest of ECI	3	–	7	–	–	10	(25)	(15)
Other	–	–	(5)	(4)	5	(4)	–	(4)
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 106	$ 1,076	$ 6,704	$ 112	$ 6,816

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Equity (continued)

Emera Incorporated

millions of Canadian dollars	Common stock	Preferred stock	Contributed surplus	Accumulated other comprehensive income ("AOCI")	Retained earnings	Emera total equity	Non-controlling interest	Total equity
2015								
Balance, December 31, 2014	$ 2,016	$ 709	$ 9	$ (347)	$ 1,012	$ 3,399	$ 306	$ 3,705
Net income of Emera Incorporated	–	–	–	–	427	427	25	452
Other comprehensive income (loss), net of tax expense of $14 million	–	–	–	484	–	484	28	512
Dividends declared on preferred stock (note 29)	–	–	–	–	(30)	(30)	–	(30)
Dividends declared on common stock ($1.6625/share)	–	–	–	–	(240)	(240)	–	(240)
Dividends paid by subsidiaries to non-controlling interest	–	–	–	–	–	–	(3)	(3)
Common stock issued under purchase plan	84	–	–	–	–	84	–	84
Senior management stock options exercised	2	–	–	–	–	2	–	2
Stock option expense	–	–	1	–	–	1	–	1
Employee Share Purchase Plan	1	–	–	–	–	1	–	1
Preferred dividends paid by subsidiaries to non-controlling interest	–	–	–	–	–	–	(12)	(12)
Redemption of preferred shares of subsidiary	–	–	–	–	–	–	(132)	(132)
Acquisition of non-controlling interest of ECI	54	–	19	–	–	73	(78)	(5)
Equity method investments	–	–	–	–	(1)	(1)	–	(1)
Balance, December 31, 2015	$ 2,157	$ 709	$ 29	$ 137	$ 1,168	$ 4,200	$ 134	$ 4,334

The accompanying notes are an integral part of these consolidated financial statements.

Notes to the Consolidated Financial Statements

As at December 31, 2016 and 2015

1. Summary of Significant Accounting Policies

The significant accounting policies for both the regulated and non-regulated operations of Emera Incorporated are as follows:

Nature of Operations

Emera Incorporated ("Emera" or the "Company") is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services.

Emera's primary rate-regulated subsidiaries and investments at December 31, 2016 included the following:

- Emera Florida and New Mexico represents TECO Energy, Inc. ("TECO Energy"), a holding company with regulated electric and gas utilities in Florida and New Mexico, which was acquired on July 1, 2016. TECO Energy's holdings include:
  - Tampa Electric Company ("TEC"), which holds the Tampa Electric Division ("Tampa Electric"), an integrated regulated electric utility, serving approximately 736,000 customers in West Central Florida and Peoples Gas System Division, ("PGS"), a regulated gas distribution utility, serving approximately 374,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 522,000 customers across New Mexico; and
  - TECO Finance, Inc. ("TECO Finance"), a wholly owned financing subsidiary of TECO Energy.
- Nova Scotia Power Inc. ("NSPI"), a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 511,000 customers;
- Emera Maine provides electric transmission and distribution services to approximately 157,000 customers in the State of Maine in the United States;
- Emera (Caribbean) Incorporated ("ECI") 100.0 per cent interest (December 31, 2015 – 95.5 per cent) includes:
  - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados, serving approximately 126,000 customers;
  - a 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), a vertically integrated utility and sole provider of electricity on Grand Bahama Island, serving approximately 19,000 customers;
  - a 51.9 per cent interest (December 31, 2015 – 49.6 per cent indirect interest) in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica, serving approximately 36,000 customers; and
  - a 19.1 per cent indirect interest (December 31, 2015 – 18.2 per cent indirect interest) in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility in St. Lucia.
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy Canada ("REC"), which expires in 2034;
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), focused on two transmission investments related to the development of an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, scheduled to be generating first power in 2019 and full power in 2020. ENL's two investments are:
  - a 100 per cent investment in NSP Maritime Link Inc. ("NSPML"), which is developing the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project is scheduled to be completed in Q4 2017 and then be in service by January 1, 2018; and
  - a 62.7 per cent investment (December 31, 2015 – 55.1 per cent) in the partnership capital of Labrador Island Link Limited Partnership ("LIL"), a $3.4 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. Nalcor Energy has indicated that the project will be in service in Q2 2018.
- a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States.

Emera also owns investments in other energy-related non-regulated companies, including:

- Emera Energy, includes:
  - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
  - Bridgeport Energy, Tiverton Power and Rumford Power ("New England Gas Generating Facilities" ("NEGG")), a 1,115 MW of combined-cycle gas-fired electricity generating capacity in the northeastern United States;
  - Bayside Power Limited Partnership ("Bayside Power"), a 290 MW gas-fired combined cycle power plant in Saint John, New Brunswick;
  - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia. Brooklyn Energy has a long-term purchase power agreement with NSPI; and
  - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 600 MW pumped storage hydroelectric facility in northern Massachusetts.
- Emera Reinsurance Limited, a captive insurance company providing insurance and reinsurance to Emera and certain affiliates, to enable more cost efficient management of risk and deductible levels across Emera;
- Emera US Finance LP, a wholly owned financing subsidiary of Emera that issued multiple series of United States dollar denominated senior, unsecured notes for the purpose of funding the acquisition of TECO Energy;
- Emera US Holdings Inc. ("EUSHI"), a wholly owned holding company for certain of Emera's assets located in the United States;
- Emera Utility Services Inc., a utility services contractor primarily operating in Atlantic Canada;
- On December 8, 2016, Emera sold the Company's remaining 4.7 per cent (December 31, 2015 – 19.6 per cent) investment in Algonquin Power & Utilities Corp. ("APUC"), a public company traded on the Toronto Stock Exchange under the symbol "AQN";
- and other investments.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). In the opinion of management, these consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

Principles of Consolidation

The consolidated financial statements of Emera include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for variable interest entities in which Emera is not the primary beneficiary. The consolidated financial statements include TECO Energy from the July 1, 2016 acquisition date through December 31, 2016.

Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain 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. An offset is recorded to property, plant and equipment, regulatory assets, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction.

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may 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, with any adjustments recognized in income in the year they arise. Actual results may differ significantly from these estimates.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator. They are designed to recover the costs of providing the regulated products or services; and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers (see note 17 for additional details).

Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to Canadian dollars at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Assets and liabilities of self-sustaining foreign operations are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average rates for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCI.

The Company designates certain United States dollar denominated debt held in Canadian functional currency companies as hedges of net investments in United States dollar denominated foreign operations. The change in the carrying amount of these investments, measured at the exchange rates in effect at the balance sheet date, and the effective portion of the hedge, is recorded in Other Comprehensive Income ("OCI"). Any ineffectiveness is reflected in current period earnings.

Revenue Recognition

Operating revenues are recognized when electricity or gas is delivered to customers or when products are delivered and services are rendered. Regulated revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity or gas is recognized at rates approved by the respective regulator and recorded based on meter readings and estimates, which occur on a systematic basis throughout a month. At the end of each month, the electricity or gas delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The accuracy of the unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Non-regulated revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured.

Revenues for energy marketing and trading operations are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

The Company records the net investment in a lease under the direct finance method for Emera Brunswick Pipeline, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The difference between the gross investment and the cost of the leased item for a direct financing lease is recorded as unearned income at the inception of the lease. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Operating revenues – regulated gas" on the Consolidated Statements of Income.

Other revenues are recognized when services are performed or goods delivered.

Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property, plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income. Where a disposition of non-regulated property, plant and equipment occurs, gains and losses are included in income as the dispositions occur.

The cost of property, plant and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, asset retirement obligations ("ARO") and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and executive, along with other costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have a future economic benefit.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. The service lives of regulated assets require the appropriate regulatory approval.

Intangible assets consist primarily of computer software, land rights and naming rights with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the asset in each category. The service lives of regulated intangible assets require the appropriate regulatory approval.

Goodwill

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of assets acquired and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment. Under the applicable accounting guidance, goodwill is subject to an annual assessment for impairment at the reporting unit level. See note 23 for further detail.

Income Taxes and Investment Tax Credits

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and 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. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned by TECO Energy and Emera Maine on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by state regulatory practices.

Emera's rate-regulated subsidiaries recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future rates, unless specifically directed by a regulator to flow deferred income taxes through earnings.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively.

Derivatives and Hedging Activities

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, and 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. These physical and financial contracts are classified as held-for-trading ("HFT"). Collectively, these contracts 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. Emera 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 AOCI 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 Tampa Electric, PGS, NMGC, 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 gain or loss is recognized in the hedged item when the hedged item is settled. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates.

Derivatives that do not meet any of the above criteria are designated as HFT derivatives and are recorded on the balance sheet at fair value, with changes normally recorded 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 where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory and property, plant and equipment, depending on the nature of the item being economically hedged. Transportation capacity arising as a result of marketing and trading transactions is recognized as an asset in "Other" and amortized over the period of the transportation contract term. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable".

Cash and Cash Equivalents

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. Total short-term investments of $183 million have an effective interest rate of 0.6 per cent at December 31, 2016 (2015 – $78 million with an effective interest rate of 0.6 per cent).

Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis.

Management estimates uncollectible accounts receivable after considering historical loss experience, customer deposits, current events and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

Inventory

Fuel and materials inventories are valued using the weighted-average cost method. These inventories are carried at the lower of weighted-average cost or net realizable value, unless evidence indicates that the weighted-average cost will be recovered in future customer rates.

Emission credits inventory are measured using the first-in-first-out method. Emission credits inventory is recognized in inventory when purchased, or allocated by the respective government agency.

Asset Impairment

Goodwill

Goodwill is not amortized, but is subject to an annual impairment test. Emera's reporting units containing goodwill assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount during the fourth quarter of each year, and interim impairment tests are performed when impairment indicators are present. If it is more likely than not that a reporting unit's fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. 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. See note 23 for further detail.

Cost and Equity Method Investments

The carrying value of investments accounted for under the cost and equity methods are assessed for impairment by comparing the fair values of these investments to their carrying values, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's fair value.

Financial Assets

The Company assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired. In the case of equity securities classified as available-for-sale, an other-than-temporary decline in the fair value of the security below its cost is considered as an indicator that the securities are impaired. In the case of debt securities classified as available-for-sale, a breach of contract, such as default or delinquency in interest or principal payments, or evidence of significant financial difficulty of the issuer is considered an indicator of impairment. If any such evidence exists for available-for-sale financial assets, the cumulative loss, measured as the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in income, is removed from AOCI and recognized in the Consolidated Statements of Income.

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 regulated 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.

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.

Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses or the right to receive benefits of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is not consolidated in the Company's consolidated financial statements.

Franchise Fees and Gross Receipts

Tampa Electric and PGS are allowed to recover from customers certain costs incurred, on a dollar-for-dollar basis, through prices approved by the Florida Public Service Commission ("FPSC"). The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues in the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Provincial, state and municipal taxes".

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statement of Income.

Stock-Based Compensation

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company accounts for its plans in accordance with the fair value based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are measured at fair value and re-measured at fair value at each reporting date with the change in liability recognized in income.

Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCI or regulatory assets.

2. Change in Accounting Policy

The new USGAAP accounting policies that are applicable to, and were adopted by, the Company in 2016, with no material impact on its consolidated financial statements, are described as follows:

Consolidation
In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities were subject to re-evaluation under the revised consolidation model.

Interest – Imputation of Interest
In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. The Company adopted this standard in Q1 2016 and December 31, 2015 balances have been retrospectively restated. This change resulted in $62 million of debt issuance costs, as at December 31, 2015, previously presented as "Other long-term assets", being reclassified as a deduction from the carrying amount of the related long-term debt and "Convertible debentures" on its Consolidated Balance Sheets.

In accordance with ASU 2015-15, *Interest: Imputation of Interest*, the Company continues to present debt issuance costs related to its revolving credit facilities and related instruments in "Other long-term assets" on its Consolidated Balance Sheets.

Compensation – Retirement Benefits
In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates.

Intangibles – Goodwill and Other – Internal-Use Software
In April 2015, the FASB issued ASU 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software licence. If a cloud computing arrangement includes a software licence, the customer would account for the software licence element of the arrangement consistent with the acquisition of other software licences. If a cloud computing arrangement does not include a software licence, the customer would account for the arrangement as a service contract. The guidance does not change USGAAP for a customer's accounting for service contracts.

Inventory – Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU 2015-11, *Inventory – Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. The Company early adopted in 2016, as permitted.

Derivatives and Hedging – Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships
In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships*. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The Company early adopted in 2016, as permitted.

Investments – Equity Method and Joint Ventures
In March 2016, the FASB issued ASU 2016-07, *Investments – Equity Method and Joint Ventures*, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. The Company early adopted in 2016, as permitted.

Compensation – Stock Compensation
In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation* to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, accounting for forfeitures, classification of awards as either equity or liabilities and presentation on the statement of cash flows. The Company early adopted in 2016, as permitted.

3. Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or have minimal impact on the consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework, which has been codified as ASC Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect narrow scope improvements and practical expedients. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018. The Company has implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its consolidated financial statements and disclosures. This includes evaluating the available adoption methods, accounting for contributions in aid of construction and contract acquisition costs, the impact of collectibility risk, unique contract characteristics in the Company's non-regulated businesses and disclosure requirements. The Company is also monitoring the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force. The ultimate impact of the adoption of ASC Topic 606, and the method of adoption, has not yet been finalized.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators.

This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows

In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Restricted Cash on the Statement of Cash Flows

In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard will require the Company to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents will no longer be presented in the statement of cash flows. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted and is required to be applied prospectively.

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*. The standard provides guidance to simplify the subsequent measurement of goodwill by eliminating the second step of the quantitative test. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. The guidance is required to be applied prospectively.

4. Acquisition

TECO Energy Inc.

On July 1, 2016, Emera acquired all of the outstanding common shares of TECO Energy for $27.55 USD per common share. The net cash purchase price totalled $8.4 billion ($6.5 billion USD), with an aggregate purchase price of $13.9 billion ($10.7 billion USD), including the assumption of $5.5 billion ($4.2 billion USD) in US debt on closing. The net cash purchase price was financed through: (i) $728 million ($560 million USD) related to the first instalment of convertible debentures represented by instalment receipts issued in 2015, $1.56 billion ($1.2 billion USD) fixed-to-floating subordinated notes, $500 million ($384 million USD) in Canadian long-term debt and $4.2 billion ($3.25 billion USD) in US long-term senior unsecured notes; (ii) available cash on hand; and (iii) drawings of $1.4 billion ($1.1 billion USD) on the Company's acquisition credit facility. Total proceeds of the debt, that were not otherwise required to complete the acquisition, have been used for general corporate purposes.

On August 2, 2016, the convertible debenture Final Instalment Date, Emera received the remaining two-thirds of the convertible debenture instalments (note 10), for net proceeds of $1.4 billion. These funds were used to repay the Company's acquisition credit facility.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy's holdings include Tampa Electric, an integrated regulated electric utility in West Central Florida, PGS, a regulated gas distribution utility serving customers across Florida, and NMGC, a regulated gas distribution utility in New Mexico.

The majority of TECO Energy's operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission ("FERC"), Florida Public Service Commission ("FPSC"), and New Mexico Public Regulation Commission ("NMPRC"), and are accounted for pursuant to USGAAP, including the accounting guidance for regulated operations. Except for unregulated long-term debt acquired and deferred taxes, preliminary fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values due to the fact that a market participant would not expect to recover any more or less than their net carrying value. Accordingly, assets acquired and liabilities assumed and pro-forma financial information do not reflect any adjustments related to these amounts.

The Acquisition is accounted for in accordance with the acquisition method of accounting. The excess of purchase price over estimated fair values of assets acquired and liabilities assumed has been recognized as goodwill at the acquisition date of July 1, 2016. The goodwill reflects the value paid for access to regulated assets, net income and cash flows in growth markets, opportunities for adjacency growth, long-term potential for enhanced access to capital as a result of increased scale and business diversity, and an improved earnings risk profile. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at July 1, 2016 based on their fair values, using the July 1, 2016 exchange rate of $1.00 USD = $1.3009 CAD. The allocation of the preliminary purchase consideration is considered preliminary due to the continued evaluation and analysis of deferred income taxes and the allocation of goodwill between reporting units.

	millions of Canadian dollars
Purchase Consideration	$ 8,447
Fair value assigned to net assets:	
Current assets [(1)]	$ 619
Regulatory assets (including current portion)	624
Property, plant and equipment, net	10,023
Other long-term assets	71
Current liabilities	(747)
Assumed long-term debt (including current portion)	(5,409)
Regulatory liabilities (including current portion)	(1,117)
Deferred income taxes	(800)
Pension and post-retirement liabilities (including current portion)	(480)
Other long-term liabilities	(146)
	$ 2,638
Cash and cash equivalents	38
Fair value of net assets acquired	$ 2,676
Goodwill	**$ 5,771**

(1) Includes accounts receivables with fair value of $334 million comprised of gross contract value of $337 million, and $3 million of contractual receivables not expected to be collected.

Goodwill has been preliminarily allocated to the TECO Energy reporting units and is subject to change as additional information is obtained through the purchase price allocation process.

millions of Canadian dollars	Goodwill
Reporting Unit	
Tampa Electric	$ 4,552
PGS	744
New Mexico Gas	475
Goodwill	**$ 5,771**

Goodwill is subject to an annual assessment for impairment at the reporting unit level. Adverse changes in assumptions could result in a material impairment of Emera's goodwill (note 23).

Acquisition Related Expenses

Acquisition related expenses totalled $250 million ($166 million after-tax) and $76 million ($53 million after-tax) for the twelve months ended December 31, 2016 and 2015, respectively. These costs have been recognized in the Consolidated Statements of Income as follows:

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Operating revenues – regulated gas	**$ (10)**	$ —
Operating, maintenance, and general	**89**	52
Interest expense, net	**148**	24
Other income (expenses), net	**(3)**	—
Income tax expense (recovery)	**(84)**	(23)
Acquisition related costs	**$ 166**	$ 53

As part of the acquisition the Company has agreed to fund certain commitments in New Mexico. These commitments include contributions relating to economic development, donations, construction of an enlarged pipeline to the New Mexico/Mexico border, establishment of a matching fund to extend gas infrastructure in New Mexico and an annual customer bill reduction credit through June 30, 2018. For the year ended December 31, 2016, Emera recognized $10 million in "Operating revenues – Regulated gas" and $30 million in "Operating, maintenance, and general" associated with these commitments for a total of $40 million ($23 million after-tax).

In addition to the New Mexico commitments, operating, maintenance, and general expenses includes acquisition related legal, accounting, banking and advisory fees and the accelerated vesting of outstanding stock-based compensation awards. Other income (expenses), net includes foreign exchange gains on acquisition related transactions. Interest expense, net includes interest incurred on the convertible debentures represented by instalment receipts and the acquisition credit facility issued for the purpose of financing the TECO Energy acquisition. In addition, it includes interest for the period between the issuance date and the acquisition date on acquisition-related debt and the Beneficial Conversion Feature discount expensed on conversion of the convertible debentures.

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of TECO Energy as if the transaction had occurred at the beginning of 2015. This pro forma data is presented for information purposes only, and does not purport to be indicative of the results that would have occurred had the acquisition taken place at the beginning of 2015, nor is it indicative of the results that may be expected in future periods.

Pro forma net income attributable to common shareholders excludes all non-recurring acquisition-related expenses incurred by TECO Energy and Emera and includes adjustments for pro forma financing costs associated with the acquisition. In addition, net income from TECO Coal, a discontinued operation sold by TECO Energy in 2015, is excluded. After-tax adjustments increased pro forma net income attributable to common shareholders by $53 million for the twelve months ended December 31, 2016. The twelve months ended December 31, 2015 after-tax adjustments were a decrease of $35 million.

Adjustments to pro forma operating revenues resulted in an increase of $10 million for the year ended December 31, 2016, with no adjustment for 2015.

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Pro forma operating revenues	**$ 6,034**	$ 6,297
Pro forma net income attributable to common shareholders	**$ 386**	$ 584

5. Segment Information

Emera manages its reportable segments separately due in part to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contribution of revenues, net income attributable to common shareholders and total assets as reported to the Company's chief operating decision maker.

As at December 31, 2016, Emera has six reportable segments, specifically:

- Emera Florida and New Mexico (includes TEC, consisting of two divisions: Tampa Electric and PGS, NMGC, their parent company TECO Energy, and TECO Finance, a wholly owned financing subsidiary of TECO Energy);
- NSPI;
- Emera Maine;
- Emera Caribbean (ECI and its subsidiaries including BLPC, Domlec, GBPC, and an equity investment in Lucelec);
- Emera Energy (Emera Energy Services, NEGG Facilities, Bayside Power, Brooklyn Energy and an equity investment in Bear Swamp); and
- Corporate and Other (Emera Utility Services, ENL, Emera Brunswick Pipeline, Corporate, other strategic investments and holding companies).

millions of Canadian dollars	Emera Florida and New Mexico (2)	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment eliminations	Total
For the year ended December 31, 2016								
Operating revenues from external customers (1)	$ 1,839	$ 1,356	$ 297	$ 419	$ 298	$ 69	$ (2)	$ 4,276
Inter-segment revenues (1)	—	—	—	—	11	24	(34)	1
Total operating revenues	1,839	1,356	297	419	309	93	(36)	4,277
Allowance for funds used during construction – debt and equity	28	6	1	—	—	—	—	35
Regulated fuel and fixed cost deferral adjustments	—	61	—	—	—	—	—	61
Depreciation and amortization	243	197	51	48	45	4	—	588
Interest expense (3)	125	127	19	15	2	312	—	600
Interest revenue	—	—	—	—	1	1	—	2
Internally allocated interest (4)	—	—	—	—	(24)	24	—	—
Income from equity investments	—	—	—	3	11	86	—	100
Income tax expense (recovery)	100	12	23	14	(53)	(118)	—	(22)
Net income attributable to common shareholders	172	130	47	100	(110)	(112)	—	227
Capital expenditures	547	304	85	87	39	7	—	1,069
As at December 31, 2016								
Total assets	18,016	4,776	1,543	1,331	1,702	1,966	(113)	29,221
Investments subject to significant influence	—	—	13	39	—	895	—	947
Goodwill	5,957	—	154	102	—	—	—	6,213

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Inter-company transactions which have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Financial results of Emera Florida and New Mexico are from July 1, 2016, the date of the acquisition.

(3) Corporate and Other Interest expense has been reduced by amortization of $13 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.

(4) Segment net income is reported on a basis that includes internally allocated financing costs.

	Emera Florida and New Mexico [2]	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment eliminations	Total
For the year ended December 31, 2015								
Operating revenues from external customers [1]	$ —	$ 1,417	$ 284	$ 442	$ 578	$ 68	$ (2)	$ 2,787
Inter-segment revenues [1]	—	—	—	8	12	24	(42)	2
Total operating revenues	—	1,417	284	450	590	92	(44)	2,789
Allowance for funds used during construction – debt and equity	—	4	2	—	—	—	—	6
Regulated fuel and fixed cost deferral adjustments	—	42	—	—	—	—	—	42
Depreciation and amortization	—	206	47	44	41	2	—	340
Interest expense	—	129	19	14	1	59	—	222
Interest revenue	—	5	—	—	1	—	—	6
Internally allocated interest [3]	—	—	—	—	(18)	18	—	—
Income from equity investments	—	—	—	3	21	84	—	108
Income tax expense (recovery)	—	23	27	3	50	(10)	—	93
Net income attributable to common shareholders	—	130	45	41	99	82	—	397
Capital expenditures	—	271	65	44	98	9	—	487
As at December 31, 2015								
Total assets	—	4,721	1,558	1,403	1,919	2,663	(225)	12,039
Investments subject to significant influence	—	—	12	39	—	1,094	—	1,145
Goodwill	—	—	158	106	—	—	—	264

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Inter-company transactions which have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Financial results of Emera Florida and New Mexico are from July 1, 2016, the date of the acquisition.
(3) Segment net income is reported on a basis that includes internally allocated financing costs.

Geographical Information

Revenues: [1]

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Canada	**$ 1,510**	$ 1,546
United States	**2,348**	786
Barbados	**254**	259
The Bahamas	**121**	154
Dominica	**44**	44
	$ 4,277	$ 2,789

(1) Revenues are based on country of origin of the product or service sold.

Property Plant and Equipment:

As at	**December 31**	December 31
millions of Canadian dollars	**2016**	2015
Canada	**$ 3,791**	$ 3,672
United States	**12,724**	2,034
Barbados	**416**	402
The Bahamas	**295**	299
Dominica	**64**	62
	$ 17,290	$ 6,469

6. Investments Subject to Significant Influence and Equity Income

Investments subject to significant influence consisted of the following:

	Carrying value as at December 31		Equity income for the year ended December 31		Percentage of ownership
millions of Canadian dollars	**2016**	2015	**2016**	2015	**2016**
LIL (1)	**$ 400**	$ 208	**$ 24**	$ 9	**62.7**
NSPML	**315**	188	**21**	15	**100.0**
M&NP (2)	**175**	189	**23**	23	**12.9**
Lucelec (2)	**39**	39	**3**	3	**19.1**
APUC (3)	**—**	504	**18**	37	**—**
Bear Swamp (4)	**—**	—	**11**	17	**50.0**
Other Investments	**18**	17	**—**	4	
	$ 947	$ 1,145	**$ 100**	$ 108	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued.
(2) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method. This is consistent with industry practice for similar investments with significant influence.
(3) On May 24, 2016, Emera completed the sale of 50.1 million common shares or 19.3 per cent of APUC's issued and outstanding common shares. This resulted in a pre-tax gain of $172 million (after-tax gain of $146 million), which was recorded in "Other income (expenses), net" in Q2 2016. On June 30, 2016, Emera exchanged 12.9 million of APUC subscription receipts and dividend equivalents into common shares. This resulted in a pre-tax gain of $63 million (after-tax gain of $53 million), which was recorded in "Other income (expenses), net" in Q2 2016. As a result of these transactions, Emera reclassified its investment in APUC from "Investments Subject to Significant Influence" to "Investment Securities" on the Consolidated Balance Sheets in Q2 2016, recorded at fair value. On December 8, 2016, Emera completed the sale of 12.9 million common shares or 4.7 per cent of APUC's issued and outstanding common shares. This sale resulted in a pre-tax loss of $12 million (after-tax loss of $10 million), which was recorded in "Other income (expenses), net" in Q4 2016. Emera no longer holds any interest in APUC.
(4) The investment balance in Bear Swamp is in a credit position primarily a result of a $179 million distribution received in Q4 2015. Bear Swamp's credit investment balance of $217 million (2015 – $225 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a $14 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 33). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at	**December 31**	
millions of Canadian dollars	**2016**	2015
Balance Sheets		
Current assets	**$ 439**	$ 439
Property, plant and equipment	**1,132**	648
Non-current assets	**276**	554
Total assets	**$ 1,847**	$ 1,641
Current liabilities	**$ 219**	$ 130
Long-term debt	**1,288**	1,288
Non-current liabilities	**25**	35
Equity	**315**	188
Total liabilities and equity	**$ 1,847**	$ 1,641

7. Other Income (Expenses), Net

Other income (expenses), net consisted of the following:

For the		Year ended December 31
millions of Canadian dollars	**2016**	2015
Gain on sale of APUC common shares (note 6)	**$ 160**	$ —
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC (note 6)	**63**	—
Gain on BLPC Self-Insurance Fund ("SIF") regulatory liability [(1)]	**53**	—
Allowance for equity funds used during construction	**22**	2
Foreign exchange (losses) gains and mark-to-market adjustments related to the TECO Energy acquisition [(2)]	**(135)**	119
Gain on sale of NWP investment [(3)]	**—**	19
Other	**11**	1
	$ 174	$ 141

(1) In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $22 million USD. As a result, Emera reduced the SIF regulatory liability to $30 million ($22 million USD) and recorded a pre-tax gain of $53 million (after-tax gain of $43 million).

(2) Mark-to-market adjustments included in Emera's other income related to the effect of TECO Energy convertible debenture related USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion 4 per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures") for the TECO Energy acquisition.

(3) On January 25, 2015, Emera completed the sale of its 49 per cent interest in NWP. This resulted in a pre-tax gain of $19 million (after-tax gain of $12 million).

8. Interest Expense, Net

Interest expense, net consisted of the following:

For the		Year ended December 31
millions of Canadian dollars	**2016**	2015
Interest on debt	**$ 443**	$ 193
Beneficial conversion feature (note 10)	**62**	—
Interest on Convertible Debentures (note 10)	**65**	23
Interest on acquisition credit facility related to the TECO Energy acquisition (note 4)	**11**	—
Allowance for borrowed funds used during construction	**(13)**	(4)
Interest revenue	**(2)**	(6)
Other	**19**	6
	$ 585	$ 212

9. Income Taxes

The income tax provision, for the years ended December 31, differs from that computed using the statutory income tax rate for the following reasons:

millions of Canadian dollars		2016		2015
Income before provision for income taxes	$	**244**	$	545
Statutory income tax rate		**31%**		31%
Income taxes, at statutory income tax rates		**76**		169
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(47)**		(31)
Non-taxable portion of gains on APUC transactions		**(34)**		–
Non-deductible (non-taxable) portion of foreign exchange and mark-to-market adjustments related to the TECO Energy acquisition		**21**		(18)
Financing deductions		**(17)**		(10)
Tax effect of equity earnings		**(10)**		(11)
Manufacturing and investment allowances		**(7)**		(5)
Foreign tax rate variance		**(5)**		2
Other		**1**		(3)
Income tax expense (recovery)	$	**(22)**	$	93
Effective income tax rate		**(9%)**		17%

The statutory income tax rate of 31 per cent represents the combined Canadian federal and Nova Scotia and New Brunswick provincial corporate income tax rates, which are the relevant tax jurisdictions for Emera.

The following reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars		2016		2015
Current income taxes				
Canada	$	**13**	$	42
United States		**18**		26
Other		**15**		5
Deferred income taxes				
Canada		**(113)**		11
United States		**151**		14
Other		**–**		(1)
Operating loss carry forwards				
Canada		**(2)**		(4)
United States		**(104)**		–
Income tax expense (recovery)	$	**(22)**	$	93

The following reflects the composition of income before provision for income taxes presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars		2016		2015
Canada	$	**71**	$	349
United States		**44**		137
Other		**129**		59
Income before provision for income taxes	$	**244**	$	545

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of Canadian dollars		2016		2015
Deferred income tax assets:				
Tax loss carry forwards	$	1,036	$	72
Regulatory liabilities – cost of removal		388		42
Tax credit carry forwards		318		7
Derivative instruments		173		204
Pension and post-retirement liabilities		147		129
Regulatory liabilities – deferrals related to derivative instruments		101		94
Asset retirement obligations		47		47
Other		355		136
Total deferred income tax assets before valuation allowance		2,565		731
Valuation allowance		(58)		(18)
Total deferred income tax assets after valuation allowance	$	2,507	$	713
Deferred income tax (liabilities):				
Property, plant and equipment	$	(3,625)	$	(960)
Derivative instruments		(202)		(264)
Net investment in direct financing lease		(103)		(89)
Other		(124)		(130)
Total deferred income tax liabilities	$	(4,054)	$	(1,443)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets		125		32
Long-term deferred income tax liabilities		(1,672)		(762)
Net deferred income tax liabilities	$	(1,547)	$	(730)

For regulated entities, to the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized, unless specifically directed otherwise by a regulator. These amounts include a gross-up to reflect the income tax associated with future revenues required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

Emera's gross net operating loss ("NOL") carry forwards, capital loss carry forwards and tax credit carry forwards as at December 31, consisted of the following:

millions of Canadian dollars		2016		2015
Canada				
NOL	$	199	$	103
Capital loss		77		84
United States				
Federal NOL	$	2,595	$	48
State NOL		1,183		225
Capital loss		14		4
Tax credit		318		30
Other				
NOL	$	22	$	14

The following table summarizes as at December 31, 2016 the deferred tax assets associated with NOL, capital loss and tax credit carry forwards and the associated expiration periods, and the valuation allowances for amounts which Emera has determined that realization is uncertain:

millions of Canadian dollars	Deferred tax asset	Valuation allowance	Net deferred tax asset	Expiration period
Canada				
NOL	$ 61	$ (27)	$ 34	2026–2036
Capital loss	16	(16)	—	Indefinite
United States				
Federal NOL	$ 908	$ —	$ 908	2024–2036
State NOL	45	(1)	44	2017–2036
Capital loss	3	(3)	—	2018–2019
Tax credit	318	—	318	2019–2036
Other				
NOL	$ 3	$ (3)	$ —	2017–2023

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for the loss carry forwards noted above and unrealized capital losses on certain investments. A valuation allowance of $58 million has been recorded as at December 31, 2016 (2015 – $18 million) related to the loss carry forwards and investments.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	**2016**	2015
Balance, January 1	**$ 6**	$ 5
Increases due to tax positions related to current year	**12**	—
Increases due to tax positions related to a prior year	**—**	1
Balance, December 31	**$ 18**	$ 6

The total amount of unrecognized tax benefits as at December 31, 2016 was $18 million (2015 – $6 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $1 million (2015 – $1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next twelve months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, US and non-US income and withholding taxes for which deferred taxes might otherwise be required have not been provided for on a cumulative amount of temporary differences related to investments in foreign subsidiaries of approximately $667 million as at December 31, 2016 (2015 – $669 million). It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera files a Canadian federal income tax return, which includes its Nova Scotia and New Brunswick provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, St. Lucia and Dominica income tax returns. As at December 31, 2016, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62 million, including interest. NSPI has prepaid $23 million of the amount in dispute, as required by CRA.

Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years. Should NSPI receive similar notices of reassessment for the years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. NSPI continues to assess its options to resolving the dispute however the outcome of the Appeal process is not determinable at this time.

10. Common Stock

Authorized: Unlimited number of non-par value common shares.

	2016			2015	
Issued and outstanding:	**millions of shares**	**millions of Canadian dollars**	millions of shares	millions of Canadian dollars
Balance, January 1	**147.21**	**$ 2,157**	143.78	$ 2,016
Conversion of Convertible Debentures	**51.99**	**2,115**	—	—
Issuance of common stock (1)	**7.69**	**338**	1.25	54
Issued for cash under Purchase Plans at market rate	**2.51**	**115**	2.10	88
Discount on shares purchased under Dividend Reinvestment Plan	**—**	**(5)**	—	(4)
Options exercised under senior management share option plan	**0.62**	**17**	0.08	2
Stock-based compensation	**—**	**1**	—	1
Balance, December 31	**210.02**	**$ 4,738**	147.21	$ 2,157

(1) In Q1 2016, Emera issued 0.06 million common shares to facilitate the creation and issuance of 0.2 million depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange. In addition, Emera completed an offering of 7.63 million common shares in December 2016, at $45.25 per common share, for net proceeds of approximately $345 million. The net proceeds were $335 million after $10 million of issuance costs, net of taxes.

As at December 31, 2016, there were the following common shares reserved for issuance: 6.6 million (2015 – 7.3 million) under the senior management stock option plan, 1.5 million (2015 – 1.6 million) under the employee common share purchase plan and 7.9 million (2015 – 3.3 million) under the dividend reinvestment plan.

The issuance of common shares under the current or proposed common share compensation arrangements will not exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2016, Emera is in compliance with this requirement.

Convertible Debentures

On September 28, 2015, to finance a portion of the acquisition of TECO Energy, Emera, through a direct wholly owned subsidiary (the "Selling Debentureholder") completed the sale of $1.9 billion aggregate principal amount of 4 per cent convertible unsecured subordinated debentures, represented by instalment receipts. On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures brought the aggregate proceeds of the Debenture Offering to $2.185 billion.

The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 (the "First Instalment") was paid on closing of the Debenture Offerings on September 28, 2015 and October 2, 2015, and the remaining $667 (the "Final Instalment") was payable on August 2, 2016 (the "Final Instalment Date"). Prior to the Final Instalment Date, the Debentures were represented by instalment receipts. The instalment receipts traded on the Toronto Stock Exchange ("TSX") from September 28, 2015 to August 2, 2016 under the symbol "EMA.IR". The Debentures will mature on September 29, 2025 and, as of the Final Instalment Date, bear interest at 0 per cent.

The proceeds of the first instalment and the over-allotment of the Debentures were $727.6 million ($681.4 million net of issue costs). The proceeds of the final instalment payment were $1.457 billion ($1.413 billion net of issue costs).

Final Instalment Notice was issued by Emera on June 29, 2016 with a payable date of August 2, 2016. At the option of the holders, each fully paid Debenture was 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 was a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures.

As the Final Instalment Date occurred prior to the first anniversary of the closing of the Debenture Offering, holders of the convertible debentures who paid the final instalment by August 2, 2016 received, in addition to the payment of accrued and unpaid interest, a make-whole payment. This represented the interest that would have accrued from the day following the Final Instalment Date up to and including September 28, 2016. Recorded in the year ended December 31, 2016 is $65 million ($45 million after-tax) of interest expense related to the Convertible Debentures including the $21 million ($14 million after-tax) make-whole payment in Q2 2016 (note 8).

As at December 31, 2016, a total of 51.99 million common shares of the Company were issued, representing conversion into common shares of more than 99.6 per cent of the Convertible Debentures. After the Final Instalment Date of August 2, 2016, debentures not converted may be redeemed by Emera at a price equal to their principal amount. At maturity, Emera has the right to pay the principal amount due in common shares to the debenture holders that have not converted, which will be valued at 95 per cent of the weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

11. Earnings Per Share

Basic earnings per share ("EPS") is determined by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan, convertible debentures and shares issued under the dividend reinvestment plan.

The following table reconciles the computation of basic and diluted earnings per share:

For the	Year ended December 31	
millions of Canadian dollars (except per share amounts)	**2016**	2015
Numerator		
Net income attributable to common shareholders	**$ 227.2**	$ 397.2
Convertible Debentures	**0.2**	—
Diluted numerator	**227.4**	397.2
Denominator		
Weighted average shares of common stock outstanding	**170.4**	144.9
Weighted average deferred share units outstanding	**1.0**	0.9
Weighted average shares of common stock outstanding – basic	**171.4**	145.8
Stock-based compensation	**0.6**	0.6
Convertible Debentures	**0.2**	—
Weighted average shares of common stock outstanding – diluted	**172.2**	146.4
Earnings per common share		
Basic	**$ 1.33**	$ 2.72
Diluted	**$ 1.32**	$ 2.71

12. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income are as follows:

For the					Year ended December 31, 2016	
millions of Canadian dollars	**(Losses) gains on derivatives recognized as cash flow hedges**	**Net change in unrecognized pension and post-retirement benefit costs**	**Net change in investment hedges**	**Net change on available-for-sale investments**	**Unrealized (loss) gain on translation of self-sustaining foreign operations**	**Total AOCI**
Balance, January 1, 2016	**$ (35)**	**$ (318)**	**$ –**	**$ –**	**$ 490**	**$ 137**
Other comprehensive income (loss) before reclassifications	**11**	**–**	**(49)**	**3**	**35**	**–**
Amounts reclassified from accumulated other comprehensive income loss	**11**	**12**	**–**	**(4)**	**–**	**19**
Equity method reclassification adjustments	**(8)**	**(3)**	**–**	**–**	**(35)**	**(46)**
Net current period other comprehensive income (loss)	**14**	**9**	**(49)**	**(1)**	**–**	**(27)**
Other	**–**	**–**	**–**	**–**	**(4)**	**(4)**
Balance, December 31, 2016	**$ (21)**	**$ (309)**	**$ (49)**	**$ (1)**	**$ 486**	**$ 106**

For the						Year ended December 31, 2015
millions of Canadian dollars	(Losses) gains on derivatives recognized as cash flow hedges	Net change in unrecognized pension and post-retirement benefit costs	Net change in investment hedges	Net change on available-for-sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCI
Balance, January 1, 2015	$ (8)	$ (425)	$ –	$ 3	$ 82	$ (348)
Other comprehensive income (loss) before reclassifications	(34)	–	–	(3)	408	371
Amounts reclassified from accumulated other comprehensive income loss (gain)	7	107	–	–	–	114
Net current period other comprehensive income (loss)	(27)	107	–	(3)	408	485
Balance, December 31, 2015	$ (35)	$ (318)	$ –	$ –	$ 490	$ 137

The reclassifications out of accumulated other comprehensive income (loss) are as follows:

For the		Year ended December 31	
		2016	2015
millions of Canadian dollars	Affected line item in the Consolidated Statements of Income	Amounts reclassified from AOCI	
Losses (gain) on derivatives recognized as cash flow hedges			
Power and gas swaps	Non-regulated fuel for generation and purchased power	**$ (2)**	$ (5)
Interest rate swaps	Income from equity investments	**1**	1
Foreign exchange forwards	Operating revenue – regulated	**12**	9
Total before tax		**11**	5
	Income tax expense	**–**	2
Total net of tax		**$ 11**	$ 7
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	OM&G	**$ 41**	$ 50
Past service costs (gains)	OM&G	**(9)**	(7)
Amounts reclassified into obligations	Pension and post-retirement benefits	**(17)**	72
Total before tax		**15**	115
	Income tax expense (recovery)	**(3)**	(8)
Total net of tax		**$ 12**	$ 107
Net change in available-for-sale investments			
	Other income (expenses), net	**$ (4)**	**$** –
Total before tax		**(4)**	–
	Income tax expense (recovery)	**–**	–
Total net of tax		**$ (4)**	$ –
Equity method reclassification adjustments			
	Investments subject to significant influence	**$ 54**	**$** –
Total before tax		**54**	–
	Income tax expense (recovery)	**(8)**	–
Total net of tax		**$ 46**	$ –
Total reclassifications out of AOCI, net of tax, for the period		**$ 65**	$ 114

13. Receivables, Net

Receivables, net consisted of the following:

As at	December 31	December 31
millions of Canadian dollars	**2016**	2015
Customer accounts receivable – billed	**$ 715**	$ 406
Customer accounts receivable – unbilled	**270**	144
Total customer accounts receivable	**985**	550
Allowance for doubtful accounts	**(13)**	(12)
Customer accounts receivable, net	**972**	538
Other	**42**	40
	$ 1,014	$ 578

14. Inventory

Inventory consisted of the following:

As at	December 31	December 31
millions of Canadian dollars	**2016**	2015
Fuel	**$ 235**	$ 185
Materials	**215**	100
Emission credits [1]	**22**	29
	$ 472	$ 314

(1) The NEGG Facilities are subject to the Acid Rain Program for sulphur dioxide emissions and the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions. The emissions credits inventory balance represents the credits purchased to offset the other current liabilities and other long-term liabilities associated with these programs.

15. Derivative Instruments

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange fluctuations on foreign currency denominated purchases and sales; and
- interest rate fluctuations on debt securities.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered "derivatives". The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the normal purchases normal sales ("NPNS") exemption are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exemption 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 exemption and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. Specifically for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in fair value from cash flow hedges is recognized in net income in the reporting period.

3. 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.

4. Derivatives entered into by Tampa Electric, PGS, NMGC, 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 gain or loss is recognized in the hedged item when the hedged item is settled. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates.

5. Derivatives that do not meet any of the above criteria are designated as HFT derivatives and are recorded on the balance sheet at fair value, with changes normally recorded 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 where another accounting treatment would apply.

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative assets		Derivative liabilities	
As at		December 31		December 31
millions of Canadian dollars	**2016**	2015	**2016**	2015
Current				
Cash flow hedges				
Power swaps	**$ 5**	$ 8	**$ 2**	$ 1
Foreign exchange forwards	**—**	—	**12**	14
	5	8	**14**	15
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**26**	—	**9**	12
Power purchases	**3**	—	**1**	—
Natural gas purchases and sales	**28**	2	**—**	1
Heavy fuel oil purchases	**6**	—	**4**	20
Foreign exchange forwards	**56**	85	**—**	10
Physical natural gas purchases and sales	**—**	2	**—**	—
	119	89	**14**	43
HFT derivatives				
Power swaps and physical contracts	**33**	151	**44**	119
Natural gas swaps, futures, forwards, physical contracts	**93**	99	**357**	359
Foreign exchange options	**—**	—	**—**	2
	126	250	**401**	480
Other derivatives				
Foreign exchange forwards	**—**	92	**1**	—
	—	92	**1**	—
Total gross current derivatives	**250**	439	**430**	538
Impact of master netting agreements with intent to settle net or simultaneously	**(105)**	(189)	**(105)**	(189)
Total current derivatives	**145**	250	**325**	349
Long-term				
Cash flow hedges				
Power swaps	**5**	12	**3**	4
Foreign exchange forwards	**—**	—	**10**	27
	5	12	**13**	31
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**57**	—	**—**	4
Power purchases	**4**	—	**3**	—
Natural gas purchases and sales	**5**	—	**2**	—
Heavy fuel oil purchases	**4**	—	**3**	17
Foreign exchange forwards	**50**	121	**—**	—
	120	121	**8**	21
HFT derivatives				
Power swaps and physical contracts	**14**	13	**27**	28
Natural gas swaps, futures, forwards and physical contracts	**18**	72	**127**	63
Foreign exchange options	**—**	1	**—**	1
	32	86	**154**	92
Other derivatives				
Interest rate swap	**—**	—	**1**	3
	—	—	**1**	3
Total gross long-term derivatives	**157**	219	**176**	147
Impact of master netting agreements with intent to settle net or simultaneously	**(26)**	(51)	**(26)**	(51)
Total long-term derivatives	**131**	168	**150**	96
Total derivatives	**$ 276**	$ 418	**$ 475**	$ 445

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Details of master netting agreements, shown net on the Consolidated Balance Sheets, are summarized in the following table:

	Derivative assets		Derivative liabilities	
As at	December 31		December 31	
millions of Canadian dollars	**2016**	2015	**2016**	2015
Regulatory deferral	**$ 10**	$ –	**$ 10**	$ –
HFT derivatives	**121**	240	**121**	240
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 131**	$ 240	**$ 131**	$ 240

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. Emera also enters into interest rate swaps to fix Bear Swamp's cost of debt. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCI, until the hedged transactions are recognized in income. The ineffective portion is recognized in income of the period. The amounts related to cash flow hedges recorded in income and AOCI consisted of the following:

For the						Year ended December 31
millions of Canadian dollars			**2016**			2015
	Power swaps	**Interest rate swaps**	**Foreign exchange forwards**	Power swaps	Interest rate swaps	Foreign exchange forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**2**	**–**	**–**	5	–	–
Realized gain (loss) in operating revenue – Regulated	**–**	**–**	**(12)**	–	–	(9)
Realized gain (loss) in income from equity investments	**–**	**(1)**	**–**	–	(1)	–
Total gains (losses) in Net income	**$ 2**	**$ (1)**	**$ (12)**	$ 5	$ (1)	$ (9)

As at						December 31
millions of Canadian dollars			**2016**			2015
	Power swaps	**Interest rate swaps**	**Foreign exchange forwards**	Power swaps	Interest rate swaps	Foreign exchange forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ 2**	**$ –**	**$ (22)**	$ 4	$ (1)	$ (42)

The Company expects $14 million of unrealized losses currently in AOCI to be reclassified into net income within the next 12 months, as the underlying hedged transactions settle.

As at December 31, 2016, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2017	2018	2019	2020
Foreign exchange forwards (USD) sales	$ 53	$ 45	$ 30	$ 30
Foreign exchange forwards (EURO) purchases	3	–	–	–

Regulatory Deferral

As previously noted, Tampa Electric, PGS, NMGC, NSPI and GBPC defer gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exemption.

The Company has recorded the following changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the						Year ended December 31
millions of Canadian dollars			**2016**			2015
	Commodity swaps and forwards	**Physical natural gas purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ 40**	**$ —**	**$ (2)**	$ (24)	$ —	$ (7)
Unrealized gain (loss) in regulatory liabilities	**101**	**(1)**	**(30)**	1	9	173
Realized (gain) loss in regulatory assets	**—**	**—**	**12**	(3)	—	—
Realized (gain) loss in regulatory liabilities	**—**	**—**	**(8)**	—	—	—
Realized (gain) loss in property, plant and equipment	**—**	**—**	**—**	—	—	(1)
Realized (gain) loss in inventory [(1)]	**5**	**—**	**(44)**	12	—	(44)
Realized (gain) loss in regulated fuel for generation and purchased power [(2)]	**17**	**(1)**	**(18)**	(16)	(7)	(18)
Total change derivative instruments	**$ 163**	**$ (2)**	**$ (90)**	$ (30)	$ 2	$ 103

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.
(2) 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.

Commodity Swaps and Forwards

As at December 31, 2016, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2017	2018–2020
millions	Purchases	Purchases
Coal (metric tonnes)	—	2
Natural Gas (Mmbtu)	42	24
Heavy fuel oil (bbls)	—	1

Foreign Exchange Swaps and Forwards

As at December 31, 2016, the Company had the following notional volumes of foreign exchange swaps and forward contracts related to commodity contracts that are expected to settle as outlined below:

	2017	2018–2020
Fuel purchases exposure (millions of US dollars)	$ 224	$ 240
Weighted average rate	1.0722	1.1138
% of USD requirements	120%	44%

The Company reassesses foreign exchange forecasts periodically and will enter into additional hedges or unwind existing hedges, as required.

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas, as well as power and natural gas swaps, forwards and futures to economically hedge those physical contracts. These derivatives are all considered HFT.

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

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Power swaps and physical contracts in non-regulated operating revenues	**$ (1)**	$ 10
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**69**	5
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(7)**	(3)
Foreign exchange options in other income (expenses), net	**(2)**	(1)
	$ 59	$ 11

As at December 31, 2016, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2017	2018	2019	2020	2021
Natural gas purchases (Mmbtu)	270	69	54	45	45
Natural gas sales (Mmbtu)	202	20	16	12	1
Power purchases (MWh)	3	—	—	—	—
Power sales (MWh)	4	—	—	—	—

Other Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to cash flow hedges which documentation requirements have not been met:

For the	Year ended December 31			
millions of Canadian dollars	**2016**		2015	
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Realized gain (loss) in other income (expense)	**$ —**	**$ (87)**	$ —	$ —
Unrealized gain (loss) in other income (expense)	**—**	**—**	—	92
Unrealized gain (loss) in interest expense, net	**2**	**—**	(3)	—
Total gains (losses) in net income	**$ 2**	**$ (87)**	$ (3)	$ 92

As at December 31, 2016, the Company had interest rate swaps in place for the $250 million non-revolving term credit facility in Brunswick Pipeline for interest payments until the debt matures in 2019.

During the year ended December 31, 2016, $1,519 million in foreign exchange forwards and swaps that were used to partially hedge proceeds for the TECO Energy acquisition settled.

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.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2016, the maximum exposure the Company has to credit risk is $1,019 million (2015 – $901 million), which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2016 was $271 million (2015 – $94 million), which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2016, the Company had $104 million (2015 – $83 million) in financial assets, considered to be past due, which have been outstanding for an average 69 days. The fair value of these financial assets is $91 million (2015 – $72 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric and gas revenue.

Concentration Risk

The Company's concentrations of risk consisted of the following:

As at		December 31, 2016			December 31, 2015
		millions of Canadian dollars	% of total exposure		millions of Canadian dollars	% of total exposure
Receivables, net					
Regulated utilities					
Residential	$	315	24%	$	189	20%
Commercial		170	13%		103	10%
Industrial		38	3%		29	3%
Other		69	5%		53	5%
		592	45%		374	38%
Trading group						
Credit rating of A- or above		52	4%		31	3%
Credit rating of BBB- to BBB+		60	5%		22	2%
Not rated		57	4%		31	3%
		169	13%		84	8%
Other accounts receivable		253	20%		120	12%
		1,014	78%		578	58%
Derivative Instruments (current and long-term)						
Credit rating of A- or above		252	20%		340	34%
Credit rating of BBB- to BBB+		1	0%		70	7%
Not rated		23	2%		8	1%
		276	22%		418	42%
	$	1,290	100%	$	996	100%

Cash Collateral

The Company's cash collateral positions consisted of the following:

As at		December 31		December 31
millions of Canadian dollars		2016		2015
Cash collateral provided to others	$	91	$	107
Cash collateral received from others		52		29

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2016, the total fair value of these derivatives, in a liability position, was $475 million (December 31, 2015 – $445 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. Fair Value Measurements

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 15), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 – Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 – Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 – Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				December 31, 2016
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 10	$ —	$ —	$ 10
	10	—	—	10
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	—	74	—	74
Power purchases	7	—	—	7
Natural gas purchases and sales	8	25	—	33
Heavy fuel oil purchases	3	5	1	9
Foreign exchange forwards	—	106	—	106
	18	210	1	229
HFT derivatives				
Power swaps and physical contracts	(7)	1	—	(6)
Natural gas swaps, futures, forwards, physical contracts and related transportation	—	4	39	43
	(7)	5	39	37
Total assets	21	215	40	276
Liabilities				
Cash flow hedges				
Power swaps	4	—	—	4
Foreign exchange forwards	—	23	—	23
	4	23	—	27
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	4	—	—	4
Heavy fuel oil purchases	—	6	—	6
Natural gas purchases and sales	1	1	—	2
	5	7	—	12
HFT derivatives				
Power swaps and physical contracts	12	5	—	17
Natural gas swaps, futures, forwards and physical contracts	4	24	389	417
	16	29	389	434
Other derivatives				
Foreign exchange forwards	—	1	—	1
Interest rate swap	—	1	—	1
	—	2	—	2
Total liabilities	25	61	389	475
Net assets (liabilities)	$ (4)	$ 154	$ (349)	$ (199)

As at				December 31, 2015
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 20	$ —	$ —	$ 20
	20	—	—	20
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	—	1	—	1
Foreign exchange forwards	—	207	—	207
Physical natural gas purchases and sales	—	—	2	2
	—	208	2	210
HFT derivatives				
Power swaps and physical contracts	38	1	(8)	31
Natural gas swaps, futures, forwards and physical contracts	—	8	57	65
	38	9	49	96
Other derivatives				
Foreign exchange forwards	—	92	—	92
	—	92	—	92
Total assets	58	309	51	418
Liabilities				
Cash flow hedges				
Power swaps	$ 5	$ —	$ —	$ 5
Foreign exchange forwards	—	41	—	41
	5	41	—	46
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	—	16	—	16
Natural gas purchases and sales	1	—	—	1
Heavy fuel oil purchases	—	37	—	37
Foreign exchange forwards	—	10	—	10
	1	63	—	64
HFT derivatives				
Power swaps and physical contracts	15	—	(2)	13
Foreign exchange options	—	4	—	4
Natural gas swaps, futures, forwards and physical contracts	14	22	279	315
	29	26	277	332
Other derivatives				
Interest rate swaps	—	3	—	3
	—	3	—	3
Total liabilities	35	133	277	445
Net assets (liabilities)	$ 23	$ 176	$ (226)	$ (27)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2016 was as follows:

	Regulatory deferral		Cash flow hedges and HFT derivatives		
millions of Canadian dollars	Oil financial derivatives	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2016	$ —	$ 2	$ (8)	$ 57	$ 51
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	—	(1)	—	—	(1)
Unrealized gains (losses) included in regulatory assets or liabilities	3	(1)	—	—	2
Total realized and unrealized gains (losses) included in non-regulated operating revenues	—	—	8	(18)	(10)
Net transfers out of Level 3	(2)	—	—	—	(2)
Balance, December 31, 2016	$ 1	$ —	$ —	$ 39	$ 40

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2016 was as follows:

	Regulatory deferral		Cash flow hedges and HFT derivatives		
millions of Canadian dollars	Oil financial derivatives	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2016	$ —	$ —	$ (2)	$ 279	$ 277
Total realized and unrealized gains (losses) included in non-regulated operating revenues	—	—	2	110	112
Balance, December 31, 2016	$ —	$ —	$ —	$ 389	$ 389

The Company evaluates the observable input of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the year ended December 31, 2016, transfers from Level 3 to Level 1 were a result of an increase in observable inputs.

Emera's Enterprise Risk Management group is responsible for valuation policies, processes and the measurement of fair value. Fair value accounting rules provide a three-level hierarchy that prioritizes the inputs used to measure fair value. When possible, determining fair value is based primarily on observable market inputs in active markets.

Contracts with quoted prices available in active markets and exchanges for identical assets or liabilities are classified as Level 1 in the hierarchy. For those contracts whereby pricing inputs are either directly or indirectly observable through markets, exchanges or third party sources, but do not qualify as Level 1, are classified as Level 2 in the hierarchy. For a Level 3 classification, the processes and methods of measurement for third-party pricing information and illiquid markets are developed with input and using the market knowledge of the trading operations within Emera and its affiliates.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives includes third-party-sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Where possible, Emera also sources multiple broker prices in an effort to evaluate and substantiate these unobservable inputs. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at					December 31, 2016
millions of Canadian dollars	**Fair value**	**Valuation technique**	**Unobservable input**	**Range**	**Weighted average**
Assets					
Regulatory deferral –	$ 1	Modelled pricing	Third-party pricing	$69.64	$69.64
Financial oil derivatives			Probability of default	0.80%	0.80%
HFT derivatives –	27	Modelled pricing	Third-party pricing	$1.41–$11.87	$3.87
Natural gas swaps,			Probability of default	0.00%–0.07%	0.01%
futures, forwards,			Discount rate	0.00%–0.32%	0.05%
physical contracts	12	Modelled pricing	Third-party pricing	$1.83–$11.87	$6.16
and related transportation			Basis adjustment	(0.11)%–0.64%	0.39%
			Probability of default	0.00%–0.05%	0.00%
			Discount rate	0.00%–0.10%	0.00%
Total assets	$ 40				
Liabilities					
HFT derivatives –	$ 386	Modelled pricing	Third-party pricing	$1.55–$11.87	$6.26
Natural gas swaps, futures,			Own credit risk	0.00%–0.07%	0.00%
forwards and physical contracts			Discount rate	0.00%–0.14%	0.02%
	3	Modelled pricing	Third-party pricing	$1.83–$11.87	$5.93
			Basis adjustment	(0.11)%–0.64%	0.27%
			Own credit risk	0.00%–0.05%	0.01%
			Discount rate	0.00%–0.10%	0.01%
Total liabilities	389				
Net assets (liabilities)	$ (349)				

As at					December 31, 2015
millions of Canadian dollars	Fair value	Valuation technique	Unobservable input	Range	Weighted average
Assets					
Regulatory deferral – Physical natural gas purchases and sales	$ 2	Modelled pricing	Third-party pricing	$5.15–$6.21	$5.72
			Probability of default	0.01%	0.01%
HFT derivatives – Power swaps and physical contracts	(8)	Modelled pricing	Third-party pricing	$26.27–$129.20	$70.45
			Correlation factor	0.98%–1.00%	0.99%
			Probability of default	0.00%–0.02%	0.00%
			Discount rate	0.00%–0.15%	0.01%
	54	Modelled pricing	Third-party pricing	$1.13–$9.12	$3.26
			Probability of default	0.00%–0.10%	0.01%
			Discount rate	0.00%–0.33%	0.04%
	3	Modelled pricing	Third-party pricing	$1.25–$15.74	$6.19
			Basis adjustment	(0.06)%–0.95%	0.68%
			Probability of default	0.00%–0.09%	0.00%
			Discount rate	0.00%–0.08%	0.00%
Total assets	$ 51				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ (2)	Modelled pricing	Third-party pricing	$26.27–$129.20	$70.82
			Correlation factor	0.98%–1.00%	0.99%
			Own credit risk	0.00%–0.02%	0.00%
			Discount rate	0.00%–0.15%	0.01%
HFT derivatives – Natural gas swaps, physical contracts	279	Modelled pricing	Third-party pricing	$0.74–$10.59	$5.58
			Probability of default	0.00%–0.03%	0.00%
			Discount rate	0.00%–0.12%	0.01%
Total liabilities	277				
Net assets (liabilities)	$ (226)				

The financial assets and liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of the following:

As at						**December 31, 2016**
millions of Canadian dollars	**Carrying amount**	**Fair value**	**Level 1**	**Level 2**	**Level 3**	**Total**
Long-term debt (including current portion)	**$ 14,744**	**$ 15,723**	**$ 78**	**$ 14,843**	**$ 802**	**$ 15,723**

As at						December 31, 2015
millions of Canadian dollars	Carrying amount	Fair value	Level 1	Level 2	Level 3	Total
Long-term debt (including current portion)	$ 4,009	$ 4,487	$ —	$ 3,841	$ 646	$ 4,487

The fair values of long-term debt instruments, classified as Level 1 in the fair value hierarchy, are valued using unadjusted quoted closing market prices that are traded in active markets.

Those classified as Level 2 are valued either by using recent quoted market prices for the instrument where the instrument is not frequently traded, by using quoted closing market prices for similar issues that are frequently traded in an active market or by using quoted market prices and applying estimated credit spreads, provided by third-party pricing services, to the par value of the security.

Those classified as Level 3 are valued by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality.

The Company has designated $1.2 billion United States dollar dominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations. A foreign currency loss of $49 million was recorded in Other Comprehensive Income for the 12 months ended December 31, 2016 (2015 – nil). There was no ineffectiveness for the 12 months ended December 31, 2016 (2015 – nil).

All other financial assets and liabilities, such as cash and cash equivalents, restricted cash, accounts receivable, short-term debt and accounts payable, are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

17. Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable for recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

Emera Florida and New Mexico

Tampa Electric and PGS are regulated separately by the FPSC. Tampa Electric is also subject to regulation by the FERC. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to their cost of providing service, plus an appropriate return on invested capital.

Base Rates – Tampa Electric

Tampa Electric's target regulated return on equity ("ROE") range is 9.25 per cent to 11.25 per cent. Based on a Stipulation and Settlement Agreement in 2013 Tampa Electric would receive a revenue increase of $110 million USD effective January 1, 2017 or the date Tampa Electric's Polk Power Station goes into service, whichever is later. The expansion of Polk Power Station went into service on January 17, 2017. The agreement also provides that Tampa Electric's allowed regulatory ROE would remain in place with a potential increase of the midpoint to 10.50 per cent from 10.25 per cent if U.S. Treasury bond yields exceed a specified threshold. This 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 per cent (or 9.5 per cent if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25 per cent (or 11.5 per cent 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 per cent from investor sources of capital.

Base Rates – PGS

PGS's base rates were based upon an ROE of 10.75 per cent, with a range between 9.75 per cent and 11.75 per cent.

In December 2016, PGS entered into a settlement agreement with the Office of Public Counsel ("OPC") regarding its filed depreciation study. The settlement agreement resulted in new depreciation rates that reduce annual depreciation by $16 million USD in 2016 and accelerated the amortization of the regulated asset related to the Manufactured Gas Plant ("MGP") environmental remediation costs. In addition, the bottom of the ROE range was decreased from 9.75 per cent to 9.25 per cent. The new bottom of the range will remain until the earlier of new base rates established in PGS's next general rate proceeding or December 31, 2020. The top of the range will continue to be 11.75 per cent and the ROE of 10.75 per cent will continue to be used for the calculation of return on investment for clauses. On February 7, 2017 the FPSC approved the settlement agreement. No change in customer rates resulted from this agreement.

As part of the settlement, PGS and OPC agreed that at least $32 million USD of PGS's regulatory asset associated with the environmental liability for current and future remediation costs related to former MGP sites will be amortized over the period 2016 through 2020. At least $21 million USD will be amortized over a two-year recovery period beginning in 2016. In 2016, PGS recorded $16 million USD of this amortization.

Base Rates – NMGC

NMGC's base rates were established in 2012 through a settlement agreement. As a condition of the 2016 NMPRC order (the "Order") approving the acquisition of TECO Energy, NMGC will not seek an increase in base rates to be effective prior to December 31, 2017, and NMGC will continue to provide an annual bill reduction credit of $4 million USD through June 30, 2018.

NSPI

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* (the "Act") and is subject to regulation under the Act by the UARB. The 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 held 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 target regulated ROE range for 2016 and 2015 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent. NSPI has a FAM, which enables it to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

On December 18, 2015, the Province enacted the *Electricity Plan Implementation (2015) Act, ("Electricity Plan Act")*, which required NSPI to file a three-year stability plan for Fuel Costs and a General Rate Application ("GRA") for non-fuel costs if required by April 30, 2016. On March 7, 2016, NSPI announced that it would not file a GRA related to non-fuel electricity rates for the 2017 to 2019 period and NSPI filed the stability plan for Fuel Costs with the UARB for 2017 through 2019.

On July 19, 2016, the UARB approved a Consensus Agreement between NSPI and customer representatives related to the Rate Stability Plan fuel costs for 2017 through 2019 which resulted in an average annual increase of 1.1 per cent for each of these three years. Subsequently, certain customer representatives requested changes resulting in amended rates that were approved by the UARB on November 15, 2016 and result in an average annual rate increase of 1.0 per cent for each of these three years.

In December 2015, the UARB approved NSPI's 2016 base cost of fuel and its recovery of prior period unrecovered Fuel Costs. The approved customer rates reset the base cost of fuel rates for 2016. In addition, $12 million was recovered of prior years' unrecovered Fuel Costs in 2016. This resulted in a combined average rate decrease for customers of approximately 1 per cent in 2016. The rates and recovery of these costs began on January 1, 2016.

On December 21, 2016, the UARB approved a settlement agreement between NSPI and customer representatives which resolved all issues related to the 2014 and 2015 FAM Audit and an issue that would impact future periods. As a result of this settlement agreement, NSPI agreed to forgo $3 million of any incentive payment as a result of 2016 fuel costs savings achieved by the Company. NSPI achieved a $2.8 million incentive payment for 2016 and contributed that plus an additional $0.2 million to the benefit of customers.

On December 12, 2016, the UARB approved NSPI's application to refund over-recovered fuel costs in 2016 to customers. The over-recovered fuel costs balance at the end of 2016 will be refunded to customers through a one-time credit on their bills prior to April 30, 2017 and will be based on individual electricity usage in 2016. The balance to be refunded to customers is approximately $36 million.

FAM and fixed cost deferrals recognized in the 2016 and 2015 Consolidated Statement of Income consisted of the following:

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
(Over-) under-recovery of current period Fuel costs	**$ 29**	$ (24)
Recovery from customers of prior years' Fuel costs	**12**	56
Application of non-fuel revenues	**20**	45
Regulated fixed cost deferral related to 2015 demand side management	**–**	(35)
Regulated fuel adjustment mechanism	**$ 61**	$ 42

Emera Maine

Emera Maine's core businesses are the transmission and distribution of electricity, with distribution operations and stranded cost recoveries regulated by the Maine Public Utilities Commission ("MPUC"). The transmission operations are regulated by the FERC. The rates for these three elements are established in distinct regulatory proceedings.

Distribution Operations

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

On December 21, 2016, Emera Maine's distribution rates increased by 3.75 per cent, including the recovery, over five years, of approximately $4 million USD of costs associated with a major storm in Maine in 2014. Also, effective December 22, 2016 the allowed ROE became 9.00 per cent on a common equity component of 49 per cent.

Transmission Operations

There are two transmission districts in Emera Maine, corresponding to the service territories of the two pre-merger entities.

Bangor Hydro District

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) local transmission rates 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. Effective June 1, 2016, transmission rates for the Bangor Hydro district increased by approximately 2 per cent in connection with its annual transmission formula rate filing (2015 – increased by 21 per cent). The increase is associated primarily with the recovery of increased transmission plant in service and as a result of the prior year tariff rate including a rate refund related to the aforementioned FERC ROE decision.

Bangor Hydro District's bulk transmission assets are managed by ISO-New England ("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. 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, 2016, Bangor District's regionally recoverable transmission investments and expenses increased by 9 per cent (2015 – decreased by 6 per cent).

MPS District

MPS District (the franchise electric service territory associated with the former Maine Public Service Company in northern Maine) local transmission rates 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 per cent. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2016 the transmission rates for the Maine Public Service district increased by approximately 43 per cent for wholesale customers (2015 – decreased by 1 per cent) and on July 1, 2016 increased by 36 per cent for retail customers (2015 – decreased by 22 per cent) in connection with its annual transmission formula rate filing. These increases were primarily due to an increase in the recovery of increased transmission plant in service.

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. Each year, stranded cost rates in each District are evaluated for a potential rate change on July 1 to recover 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 District's net 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 $11.4 million as at December 31, 2016 (2015 – $19.7 million) or 1 per cent of Emera Maine's net asset base (2015 – 1.8 per cent).

The Bangor Hydro District is currently undergoing a stranded cost rate proceeding with the MPUC to set rates for the period March 1, 2017 to February 28, 2020.

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 Maine Public Service district decreased by approximately 150 per cent. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The allowed ROE used in setting the new rates on January 1, 2015 was 6.75 per cent, with a common equity component of 48 per cent. On July 1, 2016, stranded cost rates further decreased by 7.6% to flow back over-collections associated with stranded cost reconciliation deferrals. The allowed ROE remained consistent with the January 1, 2015 rate change. The reduced stranded cost revenues are offset by reductions in expense and do not affect earnings. The Maine Public district is currently undergoing a stranded cost rate proceeding with the MPUC to set rates for the period March 1, 2017 to February 28, 2020.

The Barbados Light & Power Company Limited

BLPC is a vertically integrated utility and provider of electricity on the island of Barbados.

BLPC is subject to regulation under the Utilities Regulation (Procedural) Rules 2003 by the Fair Trading Commission ("The Rules"), Barbados, an independent regulator. The Rules give the *Fair Trading Commission, Barbados* utility regulation functions, which include establishing principles for arriving at rates to be charged, monitoring the rates charged to ensure compliance, and setting the maximum rates for regulated utility services. The government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028.

BLPC 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. BLPC's approved regulated return on rate base for 2016 and 2015 was 10 per cent.

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.

Dominica Electricity Services Ltd.

Domlec is an integrated utility on the island of Dominica and is regulated by the Independent Regulatory Commission, Dominica.

On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply Licence and a Generation Licence, 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 and 2015 was 15 per cent.

Domlec fuel costs are passed to customers through a fuel pass-through mechanism which provides the opportunity to recover substantially all fuel costs in a timely manner.

Grand Bahama Power Company Limited

GBPC is a vertically integrated utility and sole provider of electricity on Grand Bahama Island. The Grand Bahama Port Authority ("GBPA") regulates the utility and has granted GBPC a licenced, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and flexible tariff adjustment policy to ensure that fuel costs are recovered and a reasonable return earned. GBPC's approved regulated return on rate base was 8.8 per cent for 2016 and 10 per cent for 2015.

In October 2016, the island of Grand Bahama took a direct hit from Hurricane Matthew. GBPC's generation and substation infrastructure weathered the storm well, however over 2,100 transmission and distribution poles and related conduit were damaged or destroyed, as were many connections to customer homes. Restoration efforts have been completed. GBPC has recorded $28 million USD of restoration costs associated with Hurricane Matthew with no impact to net income. $21 million USD has been recorded as a regulated asset amortized over five years and $7 million USD recorded as property plant and equipment depreciating at an average 27 years. Both assets are included in Rate Base. The GBPA has approved full recovery of the storm restoration costs in this manner.

In December 2016, the GBPA approved that over a five-year period, 2017 to 2021, the all-in rate for electricity (fuel and base rates) will be held at 2016 levels. Any over-recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory deferral, until such time as the deferral is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory deferral, the excess will be placed in a new storm reserve. If balances remain within the Hurricane Matthew deferral at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick to markets in the northeastern United States. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy Canada. The pipeline is considered a Group II pipeline regulated by the National Energy Board ("NEB"). The NEB Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the NEB Act and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following:

As at	December 31	December 31
millions of Canadian dollars	**2016**	2015
Regulatory assets		
Deferred income tax regulatory assets	**$ 632**	$ 431
Pension and post-retirement medical plan	**373**	12
Environmental remediations	**49**	–
Unamortized defeasance costs	**39**	46
2015 demand side management deferral	**32**	36
GBPC Hurricane Matthew restoration	**28**	–
Stranded cost recovery	**27**	28
Debt basis adjustment	**19**	–
Deferrals related to derivative instruments	**15**	68
Cost-recovery clauses	**12**	–
Deferred bond refinancing costs	**9**	–
Regulated fuel adjustment mechanism	**–**	14
Other	**87**	64
	$ 1,322	$ 699
Current	**$ 80**	$ 94
Long-term	**1,242**	605
Total regulatory assets	**$ 1,322**	$ 699
Regulatory liabilities		
Accumulated reserve – cost of removal	**990**	94
Deferrals related to derivative instruments	**230**	$ 210
Cost-recovery clauses	**153**	–
Regulated fuel adjustment mechanism	**94**	42
Transmission and delivery storm reserve	**75**	–
Self-insurance fund (notes 7 and 33)	**30**	87
Deferred income tax regulatory liabilities	**26**	18
Bill reduction credit (note 4)	**10**	–
Other	**31**	14
	$ 1,639	$ 465
Current	**$ 362**	$ 112
Long-term	**1,277**	353
Total regulatory liabilities	**$ 1,639**	$ 465

Deferred Income Tax Regulatory Asset and Liability

To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized, unless specifically directed otherwise by a regulator.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at Emera Florida and New Mexico. It is included in rate base and earns a rate of return as permitted by the FPSC or NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

Environmental Remediation

This asset is primarily related to Peoples Gas costs associated with the environmental remediation at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust that provide the principal and interest streams to match the related defeased debt, which as at December 31, 2016, totalled $0.8 billion (2015 – $0.8 billion). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as approved by the UARB.

2015 DSM Deferral

Effective January 1, 2015, NSPI must purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The 2015 Program Costs were deferred to a regulatory asset and are recoverable from customers over an eight-year period which began in 2016. The UARB directed EffficiencyOne to review the financing options through which they would borrow the 2015 deferral amount from a commercial lender in order to repay NSPI the amount it expended on behalf of its customers in 2015. On December 2, 2016, EffficiencyOne secured the financing and advanced funds to NSPI to finance the 2015 DSM deferral. This was set up as a payable on the consolidated balance sheet, included in current and long-term other liabilities. As NSPI collects the associated amounts from customers over the next seven years, it will repay the balance to EfficiencyOne thereby reducing the liability. The 2016 annual DSM costs have not been deferred and have been charged to earnings.

Hurricane Matthew Restoration

This asset represents restoration costs incurred by GBPC associated with Hurricane Matthew. The asset is being amortized over five years and is included in rate base. The GBPA has approved full recovery of storm restoration costs.

Stranded Cost Recovery

Due to the decommissioning of a steam turbine in GBPC during 2012, the GBPA approved the recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base for 2016 to 2018.

Debt Basis Adjustment

This asset represents the difference between the fair value and pre-merger carrying amounts for NMGC's long-term debt on the date TECO Energy acquired NMGC. In accordance with purchase accounting standards, NMGC's long-term debt was valued at fair value on the Consolidated Balance Sheets. In accordance with the stipulation agreement with the NMPRC, an offsetting regulatory asset was recorded in order to eliminate the effects of purchase accounting on rate payers. The asset does not earn a return and is not included in the regulatory capital structure. It is amortized over the term of the related debt instrument.

Deferrals Related to Derivative Instruments

Tampa Electric, PGS, NMGC, NSPI and GBPC defer changes in fair value of derivatives that are documented as economic hedges or that do not qualify for NPNS exemption, as a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power or inventory, depending on the nature of the item being economically hedged. Tampa Electric deferrals related to derivative instruments are recovered through cost-recovery mechanisms on a dollar-for-dollar basis in the year following the settlement of the derivative position.

Cost-Recovery Clauses

These assets and liabilities are related to FPSC and NMPRC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

Deferred Bond Refinancing Costs

This asset represents Tampa Electric and NMGC past costs associated with refinancing debt. It does not earn a return but is instead included in the capital structure, which is used in the calculation of the weighted average cost of capital used to determine revenue requirements. It is amortized over the term of the related debt instruments.

Fuel Adjustment Mechanism

Differences between actual Fuel Costs and amounts recovered from NSPI 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. The 2016 FAM liability is recorded as a current FAM liability of $32 million to be applied in 2017 and a long-term FAM liability of $62 million to be returned to customers during the 2018 through 2019 period as legislated.

Accumulated Reserve – Cost of Removal

This regulatory liability represents the non-ARO Cost of Removal ("COR") in the accumulated reserve for depreciation of Tampa Electric and NSPI. AROs are costs for legally required removal of property, plant and equipment. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service. Prior to July 1, 2016, NSPI presented COR as a deduction in the carrying value of property, plant and equipment as part of accumulated depreciation. The total amount reclassified as at December 31, 2015 was $94 million.

Transmission and Delivery Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. Tampa Electric can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish its reserve to the current level. As a result of several named storms including Tropical Storm Colin, Hurricane Hermine and Hurricane Matthew, Tampa Electric incurred $11 million of storm costs in 2016 and 2015. On January 31, 2017, Tampa Electric petitioned the FPSC to seek full recovery of those costs as a surcharge to customers during the five-month period ended December 31, 2017.

Bill Reduction Credit

This regulatory liability represents NMGC's stipulation agreement included a commitment to provide an annual bill reduction credit to customers of $4 million USD per year through June 30, 2018, as part of Emera's acquisition of TECO Energy.

18. Related Party Transactions

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, as discussed in note 1. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies include natural gas transportation capacity revenues from M&NP reported in the Consolidated Statements of Income. Revenues from M&NP, reported in Operating revenues, Non-regulated, totalled $29 million for the year ended December 31, 2016 (2015 – $23 million).

There are no significant amounts between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2016 and 2015.

19. Prepayments and Other Current Assets

Prepayments and other current assets consisted of the following:

As at	**December 31**	December 31
millions of Canadian dollars	**2016**	2015
Capitalized transportation capacity [1]	**$ 190**	$ 223
Prepaid expenses	**57**	18
Due from related parties	**16**	2
Net investment in direct financing lease	**8**	6
Other	**5**	7
	$ 276	$ 256

(1) Capitalized transportation capacity represents the value of transportation/storage received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

20. Property, Plant and Equipment

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at		**December 31**	December 31
millions of Canadian dollars	Estimated useful life (years)	**2016**	2015
Generation	3 to 131	**$ 10,553**	$ 4,957
Transmission	28 to 77	**2,799**	1,603
Distribution	11 to 80	**5,715**	2,503
Gas transmission and distribution	10 to 85	**2,895**	—
General plant and other	3 to 50	**1,711**	932
Total cost		**23,673**	9,995
Less: Accumulated depreciation		**(7,787)**	(3,737)
		15,886	6,258
Construction work in progress		**1,404**	211
Net book value		**$ 17,290**	$ 6,469

21. Employee Benefit Plans

Emera maintains a number of contributory defined benefit and defined contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, Maine, Connecticut, Massachusetts, Rhode Island, New Mexico, Barbados, Dominica and Grand Bahama Island.

The acquisition of TECO Energy has added three defined benefit pension plans:
- TECO Energy Group Retirement Plan. An ongoing qualified pension plan covering all employees of TECO Energy, Inc. and its affiliates. This plan is a pension equity plan funded solely by employer contributions. There are no employee contributions to this plan.
- TECO Energy Group Supplemental Executive Retirement Plan. An unqualified supplemental executive retirement plan covering certain officers elected by the previous TECO Energy Board of Directors. This plan was historically unfunded, but was funded as a result of Emera's acquisition of TECO Energy.
- TECO Energy Group Benefit Restoration Plan. An unfunded supplemental executive retirement plan effective January 1, 2016. The plan provides the benefits under the TECO Energy Group Retirement Plan formula that would otherwise be restricted as a result of the Internal Revenue Code.

In addition, there are two non-pension benefit plans:
- TECO Energy Post-retirement Health and Welfare Plan. This plan offers retirees under age 65 and their dependents a self-funded health reimbursement account ("HRA") medical plan identical to that offered to active TECO Energy employees. Retirees over the age of 65 are enrolled in a Medicare Advantage plan.
- New Mexico Gas Company Retiree Medical Plan. This plan offers retirees under age 65 and their dependents a self-funded HRA medical plan identical to that offered to active TECO Energy employees. Retirees over age 65 and their dependents receive a fixed subsidy with which they can purchase additional coverage through a medical supplement program. Dental benefits are provided to retirees and spouses. Plan assets are held in a trust.

The net periodic costs below that relate to TECO Energy reflect purchase accounting at the acquisition date. In accordance with the Company's accounting policies, unamortized gains and losses and past service costs are recognized in AOCI for TECO Energy's unregulated companies and as regulatory assets for their regulated companies.

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans, were as follows:

For the				Year ended December 31
millions of Canadian dollars		**2016**		2015
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 1,520**	**$ 88**	$ 1,470	$ 102
Addition of TECO Energy, July 1, 2016	**1,035**	**277**	—	—
Service cost	**35**	**4**	22	3
Plan participant contributions	**8**	**—**	8	—
Interest cost	**79**	**9**	59	4
Plan amendments	**—**	**2**	—	(27)
Benefits paid	**(94)**	**(16)**	(61)	(6)
Actuarial losses	**(2)**	**(12)**	(15)	1
Foreign currency translation adjustment	**26**	**6**	37	11
Balance, December 31	**2,607**	**358**	1,520	88
Change in plan assets				
Balance, January 1	**1,300**	**6**	1,205	5
Addition of TECO Energy, July 1, 2016	**830**	**29**	—	—
Employer contributions	**49**	**17**	23	6
Plan participant contributions	**8**	**—**	8	—
Benefits paid	**(94)**	**(16)**	(61)	(6)
Actual return on assets, net of expenses	**93**	**2**	96	—
Foreign currency translation adjustment	**22**	**1**	29	1
Balance, December 31	**2,208**	**39**	1,300	6
Funded status, end of year	**$ (399)**	**$ (319)**	$ (220)	$ (82)

Plans with PBO/APBO in Excess of Plan Assets

The aggregate financial position for all pension plans where the PBO or, for post-retirement benefit plans, the APBO exceeds the plan assets for the years ended December 31 is as follows:

	2016		2015	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 2,579**	**$ 358**	$ 1,489	$ 87
Fair value of plan assets	**2,171**	**39**	1,261	5
Funded status	**$ (408)**	**$ (319)**	$ (228)	$ (82)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets

The ABO for the defined benefit pension plans was $2,489 million as at December 31, 2016 (2015 – $1,427 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

	2016	2015
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$ 2,462**	$ 1,424
Fair value of plan assets	**2,171**	1,261
Funded status	**$ (291)**	$ (163)

Balance Sheet

The amounts recognized in the Consolidated Balance Sheets consisted of the following:

	December 31		December 31	
As at	**2016**		2015	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	**$ (41)**	**$ (17)**	$ (4)	$ (3)
Long-term liabilities	**(367)**	**(302)**	(224)	(79)
Other asset (non-current)	**9**	**—**	9	—
Amount included in deferred tax asset	**16**	**(1)**	19	(3)
AOCL (AOCI) and regulatory assets after-tax adjustment	**620**	**45**	330	(9)
Net amount recognized at end of year	**$ 237**	**$ (275)**	$ 130	$ (94)

Amounts Recognized in AOCI and Regulatory Assets

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. Unamortized net losses and past service costs as at the acquisition date for TECO Energy's regulated companies were recorded as regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial losses (gains)	Past service (gains) costs
Defined benefit pension plans			
Balance, January 1, 2016	$ —	$ 353	$ (4)
Amortized in current period	(9)	(42)	1
Current year addition to AOCL or regulatory assets	318	19	—
Balance, December 31, 2016	$ 309	$ 330	$ (3)
Non-pension benefit plans			
Balance, January 1, 2016	$ —	$ 15	$ (27)
Amortized in current period	—	(2)	8
Current year addition to AOCL (AOCI) or regulatory assets	48	2	—
Balance, December 31, 2016	$ 48	$ 15	$ (19)

	2016		2015	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses	**$ 330**	**$ 15**	$ 353	$ 15
Past service (gains)	**(3)**	**(19)**	(4)	(27)
Regulatory assets	**309**	**48**	—	—
Total AOCL (AOCI) and regulatory assets on a pre-tax basis	**636**	**44**	349	(12)
Amount included in deferred tax asset	**(16)**	**1**	(19)	3
Net amount in AOCL (AOCI) and regulatory assets after-tax adjustment	**$ 620**	**$ 45**	$ 330	$ (9)

Benefit cost components

Emera's net periodic benefit cost included the following:

As at				December 31
millions of Canadian dollars		**2016**		2015
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 35**	**$ 4**	$ 22	$ 3
Interest cost	**79**	**9**	59	3
Expected return on plan assets	**(97)**	**(1)**	(65)	—
Current year amortization of:				
Actuarial losses	**42**	**2**	48	1
Past service costs (gains)	**(1)**	**(8)**	(1)	(6)
Regulatory assets (liability)	**9**	**—**	—	—
Total	**$ 67**	**$ 6**	$ 63	$ 1

The expected return on plan assets is determined based on the market-related value of plan assets of $1,180 million as at January 1, 2016 and $859 million as at the acquisition date for TECO Energy (2015 – $1,089 million), adjusted for interest on certain cash flows during the year. The market-related value of assets for TECO Energy was reset to equal the market value of assets as at July 1, 2016. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad basket of investment and non-investment-grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset class	Target range at market
Short-term securities	0%–5%
Fixed income	35%–50%
Equities:	
Canadian	12%–22%
Non-Canadian	36%–50%

Non-Canadian Pension Plans

Asset class	Target range at market (weighted average)
Short-term securities	0%–2%
Fixed income	40%–48%
Equities	50%–61%

Pension Plan assets are overseen by the respective Management Pension Committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

The following tables set out the classification of the methodology used by the Company to fair value its investments:

					December 31, 2016
millions of Canadian dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	—	$ 31	—	$ 31	1%
Net in-transits	—	(42)	—	(42)	(2)%
Equity securities:					
Canadian equity	—	192	—	192	9%
US equity	—	303	—	303	14%
Other equity	—	243	—	243	11%
Fixed income securities:					
Government	—	—	$ 47	47	2%
Corporate	—	—	53	53	2%
Other	—	5	14	19	1%
Open-ended investments measured at NAV (1)	$ 1,132	—	—	1,132	51%
Common collective trusts measured at NAV (2)	230	—	—	230	11%
Total	$ 1,362	$ 732	$ 114	$ 2,208	100%

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAVs are calculated daily and the funds honour subscription and redemption activity regularly.

(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seek to increase return through active management of interest rate and credit risks. The funds honour subscription and redemption activity regularly.

As at				December 31, 2015
millions of Canadian dollars	NAV	Level 1	Total	Percentage
Cash and cash equivalents	—	$ 12	$ 12	1%
Equity securities:				
Canadian equity	—	190	190	—%
US equity	—	240	240	18%
Other equity	—	240	240	18%
Other investments measured at NAV	$ 619	—	619	48%
Total	$ 619	$ 682	$ 1,301	100%

Refer to note 16 for more information on the fair value hierarchy and inputs used to measure fair value.

Canadian Post-Retirement Benefit Plans

There are no assets set aside to pay for the Canadian post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from general accounts as required.

US Post-Retirement Benefit Plans

Emera's US subsidiaries currently provide certain post-retirement health care and life insurance benefits for employees retiring after age 50 who meet eligibility requirements. Post-retirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify plans in whole or in part at any time.

Emera Maine provides retiree medical benefits to certain groups of employees. The Company's retiree medical expenses are incorporated into rate filings with its regulators and are recovered through its electric rates to customers.

TECO Energy and NMGC offers retirees under age 65 and their dependents a self-funded HRA medical plan identical to that offered to active TECO Energy employees. TECO Energy retirees over the age of 65 are enrolled in a Medicare Advantage plan. NMGC retirees over age 65 and their dependants receive a fixed subsidy with which they can purchase additional coverage through a medical supplement program. NMGC also provides dental benefits to retirees and spouses.

The target asset allocation for the Emera Maine Post-Retirement Benefits Plan is as follows:

Asset class	Target range at market
Short-term securities	10%–50%
Fixed income	0%–40%
Equities:	
US	30%–60%
Non-US	0%–60%

The assets for the NMGC Post-Retirement Benefits Plan are invested in life insurance policies. The life insurance does not mirror any specific employee benefit. The plan can tap into the cash surrender value of the life insurance policies to generate cash to pay retiree medical costs. In addition, as the individuals covered by the life insurance die, the plan receives the life insurance proceeds (less any cash surrender value previously drawn upon) to cover retiree medical costs.

The fair values of investments as at December 31, 2016, for all Post-Retirement Benefit Plans by asset category, are as follows:

					December 31, 2016
millions of Canadian dollars	**NAV**	**Level 1**	**Level 2**	**Total**	**Percentage**
Cash and cash equivalents	**—**	**$ 1**	**$ —**	**$ 1**	**3%**
Life insurance policies [1]	**—**	**—**	**33**	**33**	**85%**
Other investments measured at NAV	**$ 5**	**—**	**—**	**5**	**12%**
Total	**$ 5**	**$ 1**	**$ 33**	**$ 39**	**100%**

(1) For valuation purposes, the life insurance policies held for the NMGC retiree medical plan are valued at the cash surrender value and are considered Level 2 assets.

					December 31, 2015
millions of Canadian dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	—	$ 1	$ —	$ 1	20%
Other investments measured at NAV	$ 4	—	—	4	80%
Total	$ 4	$ 1	$ —	$ 5	100%

Refer to Note 16 for more information on the fair value hierarchy and inputs used to measure fair value.

Investments in Emera

As at December 31, 2016 and 2015, the assets related to the pension funds and post-retirement benefit plans do not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2017	$ 117	$ 25
Expected benefit payments		
2017	172	22
2018	140	23
2019	150	23
2020	156	24
2021	165	25
2022–2026	912	130

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2016		2015	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate	**3.96%**	**4.18%**	4.02%	4.04%
Rate of compensation increase	**2.82%**	**2.54%**	3.07%	3.50%
Health care trend – initial (next year)	**—**	**6.78%**	—	5.50%
- ultimate	**—**	**4.45%**	—	4.20%
- year ultimate reached	**—**	**2020**	—	2020
Benefit cost for year ended December 31:				
Discount rate	**3.79%**	**3.88%**	3.99%	3.98%
Expected long-term return on plan assets	**6.33%**	**4.43%**	5.91%	—
Rate of compensation increase	**2.88%**	**2.56%**	3.07%	3.50%
Health care trend – initial (current year)	**—**	**6.76%**	—	5.90%
- ultimate	**—**	**4.45%**	—	4.30%
- year ultimate reached	**—**	**2020**	—	2020

Figures shown are weighted averages. Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2016:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	$ 1	$ (1)
Accumulated post-retirement benefit obligation, December 31	20	(17)

Sensitivity Analysis for Defined Benefit Pension Plans

The impact on the 2016 benefit cost of a 25 basis point change in the discount rate and asset return assumptions is as follows:

millions of Canadian dollars	Increase	Decrease
Discount rate assumption	$ (7)	$ 7
Asset rate assumption	(4)	4

Amounts to Be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCL and regulatory assets, which are expected to be recognized as part of the net periodic benefit cost in fiscal 2017:

		2017
millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Actuarial gains (losses)	$ (53)	$ (1)
Past service gains	1	8
Regulatory assets	(16)	3
Total	$ (68)	$ 10

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2016 was $17 million (2015 – $9 million), with the increase due to the acquisition of TECO Energy.

22. Net Investment in Direct Financing Lease

Emera's net investment in direct financing lease primarily relates to Brunswick Pipeline. Brunswick Pipeline commenced service on July 16, 2009, transporting re-gasified LNG for Repsol Energy Canada under a 25-year firm service agreement. The agreement meets the definition of a direct financing capital lease for accounting purposes. The net investment in direct financing lease consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease. Net investment in direct financing lease consists of the following:

As at	December 31	December 31
millions of Canadian dollars	**2016**	2015
Total minimum lease payments to be received	**$ 1,194**	$ 1,202
Less: amounts representing estimated executory costs	**(223)**	(213)
Minimum lease payments receivable	**$ 971**	$ 989
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: unearned finance lease income	**(658)**	(686)
Net investment in direct financing lease	**$ 496**	$ 486
Principal due within one year (included in "Prepayments and other current assets")	**8**	6
Net investment in direct financing lease – long-term	**$ 488**	$ 480

Future minimum lease payments to be received for the next five years:

For the					Year ended December 31
millions of Canadian dollars	2017	2018	2019	2020	2021
Minimum lease payments to be received	$ 65	$ 65	$ 65	$ 65	$ 65
Less: amounts representing estimated executory costs	(11)	(11)	(12)	(12)	(12)
Minimum lease payments receivable	$ 54	$ 54	$ 53	$ 53	$ 53

23. Goodwill

The change in goodwill for the year ended December 31 is due to the following:

millions of Canadian dollars		2016		2015
Balance, January 1	$	264	$	222
Acquisition of TECO Energy as at July 1, 2016 (note 4)		5,771		—
Impairment		—		—
Change in foreign exchange rate		178		42
Balance, December 31	$	6,213	$	264

Goodwill on Emera's balance sheet relates to the acquisitions of TECO Energy (see note 4), Emera Maine and GBPC. Goodwill is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Emera's reporting units with goodwill are Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity bypasses the qualitative assessment, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Emera reviews recorded goodwill at least annually (during the fourth quarter) for each reporting unit, with interim impairment tests performed when impairment indicators are present.

A qualitative assessment was performed for Emera Maine, concluding that the fair value of the reporting unit exceeded its carrying value, and as such, no quantitative assessment was performed. The fair value for GBPC was determined using a discounted cash flow analysis. The fair values for the reporting units acquired in the TECO Energy acquisition (Tampa Electric, PGS, New Mexico Gas) have been preliminarily determined using a weighted combination of a discounted cash flow analysis, a market multiple analysis, and a comparable transactions analysis. The discounted cash flow analysis relies on management's best estimate of the reporting units' projected cash flows. It includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings before interest, taxes, depreciation and amortization ("EBITDA") of comparable public companies in estimating fair value. The comparable transaction analysis identified comparable company acquisitions within the industry and calculates the implied EBITDA multiple from the transaction, which is then applied to the last 12 months' EBITDA of the subject company.

Significant assumptions used in estimating the fair value include discount and growth rates, valuation of NOLs, utility sector market performance and transactions, projected operating and capital cash flows and the calculation of the terminal value. In addition to this quantitative analysis, management performed a qualitative assessment in Q4 2016 to ensure that there were no changes in facts or circumstances from the July 1, 2016 acquisition date that would require additional fair value testing for the Tampa Electric, PGS, and New Mexico Gas reporting units.

The company determined the fair value of reporting units exceed their book value and related goodwill carrying amounts at December 31, 2016 and December 31, 2015, resulting in no impairment charge. Adverse changes in assumptions described above could result in a future material impairment of the goodwill assigned to Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC.

24. Short-Term Debt

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

millions of Canadian dollars		2016	Weighted-average interest rate		2015	Weighted-average interest rate
TECO Energy/TECO Finance						
Advances on revolving credit and term facilities	**$**	**685**	**1.74%**		–	–%
Tampa Electric Company						
Advances on accounts receivable and revolving credit facilities		**228**	**1.49%**		–	–%
NMGC						
Advances on revolving credit facilities		**35**	**1.71%**		–	–%
NSPI						
Bank indebtedness		**1**	**2.70%**		16	2.70%
GBPC						
Advances on revolving credit facilities		**12**	**5.75%**		–	–%
Short-term debt	**$**	**961**		$	16	

The Company's total short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity		2016		2015
TECO Energy/TECO Finance – term credit facility	2017	**$**	**537**	$	–
TECO Energy/TECO Finance – revolving credit facility	2018		**403**		–
Tampa Electric Company – revolving credit facility	2018		**436**		–
Tampa Electric Company – accounts receivable revolving credit facility	2018		**201**		–
NMGC – revolving credit facility	2018		**168**		–
GBPC – revolving credit facility	2017		**17**		18
Total			**1,762**		18
Less:					
Advances under revolving credit and term facilities			**960**		–
Letters of credit issued inside credit facilities			**3**		–
Total advances under available facilities			**963**		–
Available capacity under existing agreements		**$**	**799**	$	18

The weighted average interest rate on outstanding short-term debt at December 31, 2016 was 1.73 per cent (2015 – 2.70 per cent).

Credit Facilities

TECO Energy/TECO Finance Term Credit Facility
TECO Energy has a $537 million ($400 million USD) bank credit facility maturing March 14, 2017. Interest rates on the borrowings are based on LIBOR plus a margin. TECO Finance expects to refinance the credit facility before maturity.

TECO Energy/TECO Finance Revolving Credit Facility
TECO Energy has a $403 million ($300 million USD) bank credit facility maturing December 17, 2018. Interest rates on the borrowings are based on LIBOR plus a margin.

TEC Credit Facility
TEC has a $436 million ($325 million USD) bank credit facility with a maturity date of December 17, 2018. Interest rates on the borrowings are based on LIBOR plus a margin.

TEC Accounts Receivable Facility
TEC has a $201 million ($150 million USD) accounts receivable collateralized borrowing facility with a maturity date of March 23, 2018. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates. TEC has pledged as collateral a pool of receivables equal to the borrowings outstanding in the case of default. TEC continues to service, administer and collect the pledged receivables, which are classified as receivables on the balance sheet.

NMGC Credit Agreement
NMGC has a $168 million ($125 million USD) bank credit facility with a maturity date of December 17, 2018. Interest rates on the borrowings are based on one-month LIBOR plus a margin.

25. Other Current Liabilities

Other current liabilities consisted of the following:

As at	**December 31**	December 31
millions of Canadian dollars	**2016**	2015
Accrued charges	**$ 137**	$ 130
Accrued interest on long-term debt	**96**	44
Sales and other taxes payable	**16**	4
Accrued interest on convertible debentures represented by instalment receipts (note 8)	**—**	11
Emission credits obligations [(1)]	**10**	6
Other	**22**	12
	$ 281	$ 207

(1) Throughout the three-year compliance period associated with the Regional Greenhouse Gas Initiative for carbon dioxide emissions, an obligation is recognized as gas is burned, measured at the cost to acquire credits for the related emissions. Emission credits are capitalized to inventory (note 14) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

26. Long-Term Debt

Emera's long-term debt includes the issuances detailed below. Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31, including the debt assumed on the acquisition of TECO Energy, consisted of the following:

millions of Canadian dollars	Weighted average interest rate 2016 (1)	Weighted average interest rate 2015 (2)	Maturity		2016		2015
Emera							
Bankers' acceptances, LIBOR loans	Variable	Variable	2020	**$**	**30**	$	240
Unsecured fixed rate notes	3.50%	3.85%	2019–2023		**725**		475
Fixed to floating subordinated notes (USD) (2)	6.75%	–	2076		**1,611**		–
				$	**2,366**	$	715
Emera US Finance LP							
Unsecured senior notes (USD) (2)	3.60%	–	2019–2046	**$**	**4,364**	$	–
				$	**4,364**	$	–
TECO Finance (3)							
Variable rate notes (USD)	Variable	–	2018	**$**	**336**	$	–
Fixed rate notes and bonds (USD)	5.86%	–	2017–2020		**805**		–
				$	**1,141**	$	–
Tampa Electric (4)							
Fixed rate notes and bonds (USD)	4.90%	–	2018–2045	**$**	**2,579**	$	–
				$	**2,579**	$	–
PGS							
Fixed rate notes and bonds (USD)	5.06%	–	2018–2045	**$**	**351**	$	–
				$	**351**	$	–
NMGC							
Fixed rate notes and bonds (USD)	4.53%	–	2021–2026	**$**	**363**	$	–
				$	**363**	$	–
NMGI							
Fixed rate notes and bonds (USD)	3.41%	–	2019–2024	**$**	**269**	$	–
				$	**269**	$	–
NSPI							
Commercial paper	Variable	Variable	2020	**$**	**264**	$	369
Medium term fixed rate notes	5.73%	5.73%	2019–2097		**1,965**		1,965
Fixed rate debenture	9.75%	9.75%	2019		**95**		95
Capital lease obligations	4.80%	4.58%	2019		**–**		1
				$	**2,324**	$	2,430

(continued) millions of Canadian dollars	Weighted average interest rate 2016 [(1)]	Weighted average interest rate 2015 [(2)]	Maturity		2016		2015
Emera Maine							
LIBOR loans and demand loans	Variable	Variable	2019	**$**	**32**	$	32
Secured fixed rate mortgage bonds (USD)	9.74%	9.74%	2020–2022		**67**		69
Unsecured senior fixed rate notes (USD)	4.28%	4.31%	2017–2044		**281**		296
				$	**380**	$	397
EBP							
Senior secured credit facility	3.08%	3.08%	2019	**$**	**248**	$	249
				$	**248**	$	249
GBPC							
Unsecured amortizing fixed rate notes (USD)	3.62%	3.62%	2021–2022	**$**	**63**	$	77
Unsecured senior notes (USD)	7.07%	7.07%	2020–2023		**67**		68
				$	**130**	$	145
BLPC & ECI							
Secured fixed rate senior notes [(5)]	5.65%	5.64%	2020–2028	**$**	**81**	$	89
Secured senior notes (USD) [(6)]	Variable	—	2021		**201**		—
				$	**282**	$	89
Adjustments							
Fair market value adjustment – TECO Energy acquisition [(7)]				**$**	**58**	$	—
Debt issuance costs					**(111)**		(16)
Amount due within one year					**(476)**		(274)
				$	**(529)**	$	(290)
Long-term debt				**$**	**14,268**	$	3,735

(1) Weighted average interest rate of fixed rate long-term debt.
(2) See below for details on the long-term debt related to the acquisition of TECO Energy.
(3) TECO Energy is a full and unconditional guarantor of TECO Finance's securities, and no subsidiaries of TECO Energy guarantee TECO Finance's securities.
(4) A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.
(5) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).
(6) See below for details on the long-term debt issued by ECI in November, 2016.
(7) On acquisition of TECO Energy, Emera recorded a fair market value adjustment on the unregulated long-term debt acquired. The fair market value adjustment is amortized over the remaining term of the debt.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2016	2015
Emera – revolving credit facility [1]	June 2020	$ 700	$ 700
NSPI – revolving credit facility [1]	October 2020	600	500
Emera Maine – revolving credit facility	September 2019	107	111
BLPC – revolving credit facility	2017–2021	26	26
Total		1,433	1,337
Less:			
Borrowings under credit facilities		326	641
Letters of credit issued inside credit facilities		37	33
Use of available facilities		363	674
Available capacity under existing agreements		$ 1,070	$ 663

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million.

Debt Covenants

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. Emera's significant covenants are listed below:

	Financial covenant	Requirement	As at December 31, 2016
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.62:1

Recent Financing Activity

Emera

On December 13, 2016, Emera's Series H $250 million 2.96% medium-term notes matured and were repaid.

Emera – TECO Energy Acquisition Related Capital Market Transactions

U.S. Notes

On June 16, 2016, Emera US Finance LP, a limited partnership financing subsidiary, wholly owned directly and indirectly by Emera, completed the issuance of $3.25 billion USD senior unsecured notes ("U.S. Notes") by way of private placement. The U.S. Notes were sold only to "qualified institutional buyers" under Rule 144A of the *United States Securities Act of 1933*, as amended (the "*Securities Act*") and to non-U.S. persons under Regulation S of the *Securities Act* and were not offered for sale in Canada. The U.S. Notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary. The U.S. Notes bear interest semi-annually, in arrears, on June 15 and December 15 of each year, commencing on December 15, 2016. The U.S. Notes will not be listed on a securities exchange.

The U.S. Notes issued are as follows:

- $500 million USD three-year, 2.15 per cent Notes due 2019
- $750 million USD five-year 2.70 per cent Notes due 2021
- $750 million USD ten-year 3.55 per cent Notes due 2026
- $1.25 billion USD thirty-year 4.75 per cent Notes due 2046

In connection with the initial issuance of the U.S. Notes, Emera US Finance LP entered into a registration rights agreement with the initial purchasers of the U.S. Notes in which it undertook to offer to exchange the U.S. Notes for new notes, in an equal principal amount and under the same terms, registered under the *Securities Act*. On December 15, 2016, a registration statement on Form F-10/Form S-4 was declared effective by the United States Securities and Exchange Commission (the "SEC"). On January 17, 2017 the new notes were issued.

Hybrid Notes

On June 16, 2016, Emera completed the issuance of $1.2 billion USD unsecured, fixed-to-floating subordinated notes ("Hybrid Notes"). The Hybrid Notes were issued pursuant to a prospectus filed with the Nova Scotia Securities Commission (the "NSSC") and a corresponding registration statement filed with the SEC under the United States/Canada Multijurisdictional Disclosure System. The Hybrid Notes will mature on June 15, 2076. Emera will pay interest on the Hybrid Notes at a fixed rate of 6.75 per cent per year in equal semi-annual instalments on June 15 and December 15 of each year until June 15, 2026. Beginning on June 15, 2026, and on every quarter thereafter that the Hybrid Notes are outstanding until their maturity on June 15, 2076 (the "Interest Reset Date"), the interest rate on the Hybrid Notes will be reset. The Hybrid Notes are not currently listed and Emera does not intend to list them on any securities exchange or include them on any automated quotation system.

Beginning on June 15, 2026, and on every Interest Reset Date until June 15, 2046, the Hybrid Notes will be reset at an interest rate of the three month LIBOR plus 5.44 per cent, payable in arrears. Beginning on June 15, 2046, and on every Interest Reset Date until June 15, 2076, the Hybrid Notes will be reset at an interest rate of the three-month LIBOR plus 6.19 per cent, payable in arrears.

Emera may elect, at its sole option, to defer the interest payable on the Hybrid Notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after June 15, 2026, Emera may, at its option, redeem the Hybrid Notes, at a redemption price equal to 100 per cent of the principal amount, together with accrued and unpaid interest.

Canadian Notes

On June 16, 2016, Emera completed the issuance of $500 million senior unsecured notes ("Canadian Notes"). The Canadian Notes were issued with a seven-year term to maturity and bear interest at a rate of 2.90 per cent. The notes will bear interest semi-annually in arrears on June 16 and December 16 of each year, commencing on December 16, 2016. The Canadian Notes will not be listed on a securities exchange.

The proceeds of the U.S. Notes, Hybrid Notes and Canadian Notes offerings were used to partially finance the purchase price for the Acquisition. Proceeds of the offerings, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

NSPI

On April 28, 2016, NSPI increased its committed syndicated revolving bank line of credit to $600 million from $500 million. The increase will support ongoing business requirements and general corporate purposes.

On May 27, 2016, NSPI increased its commercial paper program to $500 million from $400 million, of which the full amount outstanding is backed by NSPI's operating credit facility referred to above. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

ECI

On November 29, 2016, ECI completed a senior, secured floating rate, non-revolving term loan of $150 million USD. The loan is for a five-year term and matures on November 29, 2021. Interest is due semi-annually and is based on six-month LIBOR plus 4.08 per cent weighted average.

TECO Finance

On April 10, 2015, TECO Finance completed an offering of $250 million USD aggregate principal amount of floating rate notes due 2018 ("the 2018 Notes"), which are guaranteed by TECO Energy. The 2018 Notes were sold at par and mature on April 10, 2018. The 2018 Notes bear interest at a floating rate that is reset quarterly based on the three-month LIBOR plus 60 basis points. The 2018 Notes are not subject to redemption prior to maturity. The 2018 Notes are effectively subordinated to existing and future liabilities of TECO Energy's subsidiaries to their respective creditors, and also are effectively subordinated to any secured debt that TECO Finance and TECO Energy incur to the extent of the value of the assets securing that indebtedness.

Tampa Electric

On May 20, 2015, TEC completed an offering of $250 million USD aggregate principal amount of 4.20 per cent notes due May 15, 2045.

Long-Term Debt Maturities

As at December 31, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2017	2018	2019	2020	2021	Thereafter	Total
Emera	$ —	$ —	$ 225	$ 30	$ —	$ 2,111	$ 2,366
Emera US Finance LP	—	—	671	—	1,007	2,686	4,364
TECO Energy	—	409	67	—	643	2,443	3,562
TECO Finance	403	335	—	403	—	—	1,141
NSPI	—	—	95	264	—	1,965	2,324
Emera Maine	33	6	32	40	—	269	380
EBP	—	—	248	—	—	—	248
GBPC	11	12	12	40	11	44	130
BLPC and ECI	29	29	30	58	26	110	282
Total	$ 476	$ 791	$ 1,380	$ 835	$ 1,687	$ 9,628	$ 14,797

27. Asset Retirement Obligations

AROs mostly relate to the reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional ARO that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars		**2016**		2015
Balance, January 1	**$**	**109**	$	106
Additions [(1)]		**48**		—
Additions due to acquisition		**9**		—
Liabilities settled		**(2)**		(2)
Accretion included in depreciation expense		**7**		8
Accretion deferred to regulatory asset (included in property, plant and equipment)		**(2)**		(8)
Other		**1**		5
Balance, December 31	**$**	**170**	$	109

(1) Tampa Electric produces ash and other by-products known as coal combustion residuals ("CCRs") at its Big Bend and Polk power stations. The 2016 additions to ARO are to achieve compliance with the EPA's CCR rule, which contains design and operating standards for CCR management units. In 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the Environmental Cost Recovery Clause. However, additional petitions will be submitted for recovery of future project expenses based on engineering studies currently being performed.

As at December 31, 2016 and 2015, some of the Company's transmission and distribution assets may have additional conditional ARO which are not recognized in the financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

28. Commitments and Contingencies

A. Commitments

As at December 31, 2016, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2017	2018	2019	2020	2021	Thereafter	Total
Purchased power [(1)]	$ 253	$ 224	$ 206	$ 202	$ 198	$ 2,272	$ 3,355
Fuel and gas supply	475	161	109	28	22	—	795
Demand Side Management	42	48	13	—	—	—	103
Transportation [(2)]	496	392	310	280	196	1,622	3,296
Long-term service agreements [(3)]	92	55	67	44	42	227	527
Capital projects	133	—	—	—	—	—	133
Equity investment commitments [(4)]	236	—	—	200	—	—	436
Leases and other [(5)]	66	17	14	12	8	70	187
	$ 1,793	$ 897	$ 719	$ 766	$ 466	$ 4,191	$ 8,832

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(3) 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.
(4) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to the Labrador Island Link Limited Partnership upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amounts as the projects advance through construction.
(5) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

In connection with the acquisition of TECO Energy, Emera made certain commitments approved by the NMPRC. See note 4 for additional information.

Beginning in 2018, NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over 35 years. The timing and amount of future payments could change based on UARB approval and final costing of the Maritime Link after construction is complete.

B. Legal Proceedings

Emera

Between September 16, 2015 and November 2, 2015, purported shareholders of TECO Energy filed 12 separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida or the United States District Court for the Middle District of Florida (the "Merger Litigation"). Each complaint alleges, among other things, that the Board of Directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and that Emera and/or Emera US Inc. aided and abetted such alleged breaches. The complaints sought to enjoin the merger pursuant to the acquisition agreement.

On November 17, 2015, TECO Energy, Emera, Emera US Inc. and the Board of Directors of TECO Energy entered into a memorandum of understanding with the shareholder plaintiffs to settle all of the Merger Litigation, subject to negotiation of a stipulation of settlement with the plaintiffs and to court approval. The memorandum of understanding provides for all claims against the defendants to be released in exchange for TECO Energy making certain additional disclosures to its shareholders related to the proposed merger, which have now been made.

On December 16, 2016, the judge entered an order and final judgment approving a stipulation of settlement negotiated by the parties, thereby concluding this matter.

Emera Florida and New Mexico

TECO Coal

TECO Coal was sold by TECO Energy on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"), prior to Emera's acquisition. On March 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified. The claim asserted breach of certain representations, and fraud and wilful misconduct in connection therewith, of the Securities Purchase Agreement dated September 21, 2015 by and between TECO Diversified and Cambrian related to the purchase of TECO Coal by Cambrian. While the outcome of such matter is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the Company's results of operations, financial condition or cash flows.

TECO Guatemala Holdings ("TGH")

On December 19, 2013, the International Centre for the Settlement of Investment Disputes ("ICSID") Tribunal hearing the arbitration claim of TGH, a wholly owned subsidiary of TECO Energy, against the Republic of Guatemala (Guatemala) under the Dominican Republic Central America – United States Fee Trade Agreement, issued an award in the case ("the Award"). The ICSID Tribunal unanimously found in favour of TGH and awarded damages to TGH of approximately $21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus 2 per cent.

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.

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 favour 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 $21 million USD 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. As a result, TGH had the right to resubmit its arbitration claim against Guatemala to seek additional damages (in addition to the previously awarded $21 million USD), as well as additional interest on the $21 million USD, and its full costs relating to the original arbitration and the new arbitration proceeding.

On September 23, 2016, TGH filed a request for resubmission to arbitration. On October 3, 2016, ICSID issued a notice of registration for TGH's request for resubmission. TGH and Guatemala have each selected an arbitrator and ICSID has recently selected a President for the new tribunal. Results to date do not reflect any benefit.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its Peoples Gas 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 at December 31, 2016, TEC has estimated its ultimate financial liability to be $43 million ($32 million USD), primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

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 actual percentage 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. The FPSC has approved, as part of the PGS depreciation settlement as discussed in note 17, an agreement to accelerate the amortization of the regulated asset associated with this reserve.

Emera Maine

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 ROE under the ISO-New England ("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 that changed the methodology used to set the ROE and resulted in a lower base transmission ROE of 10.57 per cent and a lower total ROE (inclusive of incentive adders) of 11.74 per cent for the period of October 1, 2011 to December 31, 2012. The ROE was confirmed by FERC in two subsequent orders and has now been appealed to the U.S. Court of Appeals for the DC Circuit. The Court has decided to hold the appeal of this case in abeyance pending the outcome of the ENE Case and MA AG II Case discussed below.

On June 30, 2016, Emera Maine completed the processing of refunds to customers to reflect the 10.57 per cent ROE.

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 per cent base ROE under the OATT was unjust and unreasonable ("the ENE Case"). This complaint applies to the period from January 1, 2013 to 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 on similar grounds ("the MA AG II Case") in relation to the period from July 31, 2014 to October 31, 2015. The ENE Case and MA AG II Case were subsequently consolidated by FERC into a single case.

On March 22, 2016, a FERC Administrative Law Judge ("ALJ") issued a recommended decision to FERC with respect to the consolidated cases. The recommendation for the ENE Case was a 9.59 per cent base ROE, with a 10.42 per cent maximum ROE, and the recommendation for the MA AG II Case was a 10.90 per cent base ROE, with a 12.19 per cent maximum ROE. The ALJ's recommended decision is not definitive and FERC has the ability to adjust the ALJ's recommended decision. A decision by FERC is not expected until early 2017.

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 ROE to 8.61 per cent and the maximum ROE to 11.24 per cent for the period April 29, 2016 to July 29, 2017.

Emera Maine has recorded a reserve of $5 million pre-tax ($4 million USD) (December 31, 2015 – $7 million or $5 million USD) for the ENE Case and MA AG II Case. The reserves recorded for these complaints have been recorded as "Regulatory Liabilities" on the Consolidated Balance Sheets and as a reduction to "Operating revenues – regulated electric" 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.

Other Legal Proceedings
Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

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. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 28A. The estimated expenditures do not include 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.

Emera Florida and New Mexico
Tampa Electric operates fossil fuel burning power plants with air emissions regulated by the *Clean Air Act* and material *Clean Water Act* implications and impacts by federal and state legislative initiatives. Tampa Electric has achieved the emission-reduction levels called for in Phase I and Phase II of Clean Air Interstate Rule ("CAIR") and these expenses were rate recoverable under the Florida environmental cost recovery clause ("ECRC") as approved by the FPSC. Similarly, future expenses should be eligible for recovery upon petition by Tampa Electric and approval by the FPSC. On July 7, 2011, EPA released its final CAIR-replacement rule, called Cross-State Air Pollution Rule ("CSAPR"). An update to CSAPR was finalized on October 26, 2016 and will be implemented in 2017. Based on updated EPA modelling and favourable consideration of atmospheric dynamics, Florida is no longer subject to CSAPR requirements. However, Florida (including Tampa Electric power plants) could be subject to a future version of CSAPR as a result of an expected update triggered by compliance with the more stringent 2015 ozone standard or ongoing litigation related to current rule applicability.

NSPI
NSPI's activities are subject to a broad range of federal, provincial, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste.

In November 2014, the Government of Canada and the Province of Nova Scotia entered into a greenhouse gas ("GHG") emission regulations equivalency agreement, which allows NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

In March 2016, Canada's First Ministers issued the "Vancouver Declaration" on clean growth and climate change. First Ministers agreed to develop a Pan-Canadian Framework and implement it by early 2017. Four working groups, comprised of federal, provincial and territorial officials, were established to provide recommendations and research to the federal government.

NSPI provided input into this process through the Nova Scotia government, the Government of Canada and directly to the working groups through the submission of a discussion paper.

In October 2016, the Government of Canada announced that the Pan-Canadian Framework would include a national price on carbon component, implemented by 2018 through either a carbon tax or a cap and trade system, applicable in each province except those which enact their own comparable carbon pricing mechanism by that time.

On November 21, 2016, the Government of Canada announced a second component of the plan would include an accelerated plan to phase out coal in Canada, to transition Canada's electricity system towards 90 per cent non-emitting generation sources by 2030.

On the same day, the Province of Nova Scotia and the Government of Canada made two announcements regarding Nova Scotia's participation in the Pan-Canadian plan:

Carbon pricing component

An agreement in principle covering the carbon component had been reached and will be governed on the following principles:

- Nova Scotia will adopt a province-wide 2030 emissions reduction target equal to or greater than Canada's target of a 30 per cent reduction from 2005 levels by 2030;
- Nova Scotia will implement an agreed upon cap and trade system; and
- The Province of Nova Scotia and the Government of Canada will agree upon a methodology and scenarios for the modelling of projected GHG emissions to support the development of Nova Scotia's cap and trade system.

Accelerated phase-out of coal component

Nova Scotia and the Government of Canada will establish a new equivalency agreement that will enable the province to move directly from fossil fuels to clean energy sources and enable NSPI's coal-fired plants to operate at some capacity beyond 2030.

On December 9, 2016, the Government of Canada and eight provinces (including Nova Scotia) signed the Pan-Canadian Framework on Clean Growth and Climate Change. The Government of Canada has committed to ensuring that the provinces and territories have the flexibility to design their own policies and programs to meet emission-reduction targets, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies. Details under the agreements are expected to be finalized by the end of 2017. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions would be recoverable from customers under NSPI's regulatory framework. NSPI will continue to work with both the Province of Nova Scotia and the Government of Canada as the details of the agreements are finalized and to advance solutions that are in the best interest of customers.

The Government of Canada has indicated their intention to resume discussions regarding Base Level Industrial Emission Requirements ("BLIER"s) for sulphur dioxide and nitrogen dioxide and have outlined their intention to develop a Clean Energy Standard for natural gas and possibly diesel. The details of both processes are not yet known. NSPI will participate in these processes in 2017.

NSPI estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations will be approximately $41 million during fiscal 2017 and are estimated to be $41 million from 2018 through 2021. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 28A.

Conformance with legislative and NSPI internal 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, 2016.

Polychlorinated Biphenyl Equipment

In response to the *Canadian Environmental Protection Act 1999*, 2008 Polychlorinated Biphenyl ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil-filled electrical equipment on its system that fall under the 2008 PCB Regulations Standard by the end of 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be $43 million and, as at December 31, 2016, approximately $28 million (December 31, 2015 – $20 million) has been spent to date. NSPI has recognized an ARO on the balance sheet of $11 million as at December 31, 2016 (December 31, 2015 – $15 million) associated with the PCB phase-out program.

Emera Energy Emissions

The NEGG Facilities are subject to the RGGI for carbon dioxide emissions and the Acid Rain Program for sulphur dioxide emissions. The NEGG Facilities emit 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.

D. Principal Risks and Uncertainties

In this section, Emera describes some of the principal risks management believes could materially affect Emera's business, revenues, operating income, net income, net assets or liquidity or capital resources in the near term. The nature of risk is such that no list can be comprehensive, and other risks may arise, or risks not currently considered material may become material in the future.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management.

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. As cost-of-service utilities with an obligation to serve customers, Tampa Electric, PGS, NMGC, 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 as an adjustment 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 (including shifts in policy which could occur as a result of climate change concerns) and changes in governments. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include: NSPML, LIL, M&NP and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies and their respective regulators determine whether to allow recovery and to adjust rates based upon the 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.

Weather and Climate Risk

Shifts in weather patterns affect energy sales and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring service to customers as a result of unplanned outages. Emera responds to outages which occur as a result of significant weather events according to each subsidiary's respective emergency services restoration plan.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters; primarily related to its utility operations. This includes laws setting GHG emissions standards and air emissions standards. Emera is also subject to laws 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. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

New emission reduction 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 enforcement of such laws 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.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of achieving full compliance with applicable laws, legislation and company policies and standards. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance with such laws, policies and standards.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates globally, with an increasing amount of the Company's adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. 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.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes, or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries are included in AOCI.

Capital Market and Liquidity Risk

Emera's 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. After giving effect to the TECO Energy acquisition, Emera now has total debt of $15 billion. 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.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, and liquidity. A change to a credit rating as a result of changes in any of these items 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.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting 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.

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.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. While regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise 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.

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 and monitoring 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.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax benefits are determined by existing tax laws and could be negatively impacted by changes in 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 the corporate income tax rate. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would also reduce the value of the Company's existing deferred tax assets and could result in a charge to earnings if written down. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

E. Guarantees and Letters of Credit

Emera had significant guarantees and letters of credit on behalf of third parties outstanding as discussed below. These are not included within the Consolidated Balance Sheets as at December 31, 2016.

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 $1.577 billion, which reduces in the ordinary course as project costs are paid. The current exposure as at December 31, 2016 is $577 million.

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond 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. As a result of the sale in September 2015, the letters of indemnity guaranteed $124 million ($95 million USD).

TECO Energy has remaining letters of indemnity related to TECO Coal, which totalled $80 million ($59 million USD) at December 31, 2016. As of that date Cambrian had posted approximately $54 million ($40 million USD) of additional reclamation bonds to replace corresponding reclamation bonds supported by TECO Energy's indemnity. TECO Energy's indemnity obligations in respect of such bonds will not be released until the applicable State department processes the applicable permit transfers and releases such bonds. 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 to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety.

The amounts outlined above represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies.

The company is working with Cambrian on the process to replace the remaining bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

NSPI has a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2017 and is renewed annually. The amount committed as at December 31, 2016 was $47 million.

Emera has standby letters of credit in the amount of $24 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.

Collaborative Arrangements

For the years ended December 31, 2016 and 2015, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in operating, maintenance and general ("OM&G") expenses. In 2016, NSPI recognized $18 million net expense (2015 – $10 million) in "Regulated fuel for generation and purchased power" and $5 million (2015 – $2 million) in OM&G.

29. Cumulative Preferred Stock

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

			December 31, 2016		December 31, 2015	
	Annual dividend per share	Redemption price per share	**Issued and outstanding**	**Net proceeds**	Issued and outstanding	Net proceeds
Series A	$ 0.6388	$ 25.00	**3,864,636**	**$ 95**	3,864,636	$ 95
Series B	Floating	$ 25.00	**2,135,364**	**$ 52**	2,135,364	$ 52
Series C	$ 1.0250	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 26.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0625	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Total			**29,000,000**	**$ 709**	29,000,000	$ 709

On August 17, 2015, Emera announced that 2,135,364 of its 6,000,000 issues and outstanding Series A Shares were tendered for conversion, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series B (the "Series B Shares"). As a result of the conversion, Emera has 3,864,636 Series A Shares and 2,135,364 Series B Shares issued and outstanding. The 2016 dividends for the Series A and Series B shares were $0.6388 per share and $0.5724 respectively.

The First Preferred Shares, Series A, C and F, are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.6388, $1.025 and $1.0625 per share per annum, respectively for each year up to and excluding August 15, 2020, August 15, 2018, and February 15, 2020, respectively. As at August 15, 2020, August 15, 2018, and February 15, 2020, the holders of the First Preferred Shares Series A, C and F, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preferred Shares, Series A, C and F, respectively, which is the sum of the five-year Government of Canada Bond Yield on the application reset date plus 1.84 per cent, 2.65 per cent, and 2.63 per cent, respectively.

The First Preferred Shares, Series B, are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation in the amount determined by multiplying $25.00 by the three-month Government of Canada Treasury Bill rate plus 1.84 per cent.

The First Preferred Shares, Series E, are entitled to receive fixed rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation in the amount $1.1250 per share per annum.

The holders of First Preferred Shares, Series A, C and F will have the right, at their option, to convert their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series B, D, and G, of the Company, respectively, on August 15, 2020 August 15, 2018, and February 15, 2020, respectively, and every five years thereafter.

The holders of the First Preferred Shares, Series B will have the right, at their option, to convert their shares into an equal number of Series A shares of the Company on August 15, 2020 and every five years thereafter.

The Company has the right to redeem the outstanding Preferred Shares, Series A, C, and F shares without the consent of the holder on August 15, 2020, August 15, 2018, and February 15, 2020 respectively and on August 15, August 15 and February 15 respectively every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

The Company has the right to redeem the outstanding Preferred Shares, Series B, Series D and Series G shares without the consent of the holder on August 15, 2020, August 15, 2023 and February 15, 2025 respectively and on August 15, August 15 and February 15 every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2015, August 15, 2018 and February 15, 2020, respectively.

The Company has the right to redeem the outstanding First Preferred Shares, Series E on or after August 15, 2018 in whole or in part, at the Company's option, by the payment in cash of $26.00 per Series E Preferred Share if redeemed prior to August 15, 2019; at $25.75 per Series E Preferred Share if redeemed on or after August 15, 2019, but prior to August 15, 2020; at $25.50 per Series E Preferred Share if redeemed on or after August 15, 2020, but prior to August 15, 2021; at $25.25 per Series E Preferred Share if redeemed on or after August 15, 2021, but prior to August 15, 2022; and at $25.00 per Series E Preferred Share if redeemed on or after August 15, 2022, in each case together with all accrued and unpaid dividends up to but excluding the date fixed for redemption.

As the First Preferred Shares, Series A, B, C, E and F are neither redeemable at the option of the shareholder nor have a mandatory redemption date, they are classified as equity and the associated dividends will be deducted on the consolidated statements of earnings immediately before arriving at "Net earnings attributable to common shareholders" and will be shown on the consolidated statement of equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares will be entitled to attend any meeting of shareholders of the Company 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 any such meeting.

30. Non-Controlling Interest in Subsidiaries

Non-controlling interest in subsidiaries consisted of the following:

As at	December 31	December 31
millions of Canadian dollars	**2016**	2015
ICDU	**$ 53**	$ 52
Preferred shares of GBPC	**34**	34
Domlec	**25**	23
ECI (1)	**—**	25
	$ 112	$ 134

(1) On December 17, 2015, an indirect wholly owned subsidiary of Emera acquired approximately 2.6 million ECI shares, increasing its ownership interest from 80.7 per cent to 95.5 per cent. On March 22, 2016, an indirect wholly owned subsidiary of Emera acquired 0.7 million ECI shares (which owns 51.9 per cent share of Domlec), increasing Emera's ownership interest in ECI from 95.5 to 100 per cent.

Preferred shares of GBPC:

Authorized:
35,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2016		2015	
Issued and outstanding:	**number of shares**	**millions of dollars**	number of shares	millions of dollars
Outstanding as at December 31	**35,000**	**$ 34**	35,000	$ 34

GBPC Non–Voting Cumulative Variable Perpetual Preferred Stock:
The Preferred Stock is redeemable by GBPC, in whole at any time or in part from time to time, at $1,000 Bahamian per share plus accrued and unpaid dividends.

The Preferred Stock is entitled to a 7.25 per cent per annum fixed cumulative preferential dividend for years 2013 through 2016, 8.50 per cent per annum fixed cumulative preferential dividend for years 2017 through 2019 and 10.00 per cent per annum fixed cumulative preferential dividend after 2020, as and when declared by the Board of Directors, accruing from the date of issue.

The Preferred Shares rank behind all of GBPC's current and future secured and unsecured debt with any of GBPC's future preferred stock and ahead of all of GBPC's current and future common stock.

31. Supplementary Information to Consolidated Statements of Cash Flows

For the	Year ended December 31	
millions of Canadian dollars	**2016**	2015
Changes in non-cash working capital:		
Receivables, net	**$ (104)**	$ (19)
Income taxes receivable	**(23)**	(22)
Inventory	**88**	(2)
Prepayments and other current assets	**(18)**	9
Accounts payable and customer deposits	**162**	(45)
Income taxes payable	**14**	(32)
Other current liabilities	**15**	9
Total non-cash working capital	**134**	(102)
Supplemental disclosure of cash paid (received):		
Interest	**$ 480**	$ 196
Income taxes	**$ 57**	$ 124
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 103**	$ 78
Beneficial Conversion Feature of the convertible debentures	**$ 43**	$ —

32. Stock-Based Compensation

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in Emera's Employee Common Share Purchase Plan to which employees make cash contributions of a minimum of $25 to a maximum of $8,000 per year for the purpose of purchasing common shares of Emera. The Company also contributes to the plan a percentage of the employees' contributions. If an employee contributes any amount up to $3,000 to employees plan account, the Company will contribute 20 per cent of that amount. When an employee contributes any amount over $3,000, up to the $8,000 maximum, the Company will contribute 10 per cent of that amount.

The plan allows the reinvestment of dividends. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 4 million common shares.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan"), which provides an opportunity for shareholders to reinvest dividends and for the purpose of purchasing common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividend.

Compensation cost for shares issued by Emera for the year ended December 31, 2016 under the Employee Common Share Purchase Plan was $1 million (2015 – $1 million) and is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

Stock-Based Compensation Plans

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 11.7 million shares.

All options granted to date are exercisable on a graduated basis with up to 25 per cent of options exercisable on the first anniversary date and further 25 per cent increments on each of the second, third and fourth anniversaries of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to retirement or termination for other than just cause, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the 24 months following the date the optionee retires, but in any case prior to the expiry of the option in accordance with its terms.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to employment termination for just cause, resignation or death, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the six months following the date the optionee is terminated, resigns or dies, as applicable, but in any case prior to the expiry of the option in accordance with its terms.

The Company uses the fair value based method to measure the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis. The fair value of stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model. The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the Bank of Canada five-year government bond yields. The expected dividend yield incorporates current dividend rates as well as historical dividend increase patterns. Emera's expected stock price volatility was estimated using its five-year historical volatility.

The following table shows the weighted average fair values per stock option along with the assumptions incorporated into the valuation models for options granted:

For the year ended December 31	2016	2015
Weighted average fair value per option	$ 2.80	$ 2.66
Expected term	5 years	5 years
Risk-free interest rate	0.66%	0.73%
Expected dividend yield	4.08%	3.65%
Expected volatility	15.45%	14.58%

The following table summarizes information related to the stock options for 2016:

	Total options		Non-vested options [1]	
	Number of options	Weighted average exercise price per share	Number of options	Weighted average grant date fair value
Outstanding as at December 31, 2015	2,927,068	$ 33.07	1,453,486	$ 2.64
Granted	615,100	46.19	615,100	2.80
Exercised	(622,168)	25.65	N/A	N/A
Forfeited	—	—	(548,461)	2.68
Options outstanding December 31, 2016	**2,920,000**	**$ 37.42**	**1,520,125**	**$ 2.69**
Options exercisable December 31, 2016 [2][3]	**1,399,875**	**$ 33.35**		

(1) As at December 31, 2016 there was $3 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 2.4 years (2015 – $3 million, 2.3 years).
(2) As at December 31, 2016, the weighted average remaining term of vested options was 5.7 years with an aggregate intrinsic value of $17 million (2015 – 5.3 years, $21 million).
(3) As at December 31, 2016 the fair value of options that vested in the year was $2 million (2015 – $1 million).

Compensation cost recognized for stock options for the year ended December 31, 2016 was $2 million (2015 – $1 million), which is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

As at December 31, 2016, cash received from option exercises was $16 million (2015 – $2 million). The total intrinsic value of options exercised for the year ended December 31, 2016 was $13 million (2015 – $1 million). The range of exercise prices for the options outstanding as at December 31, 2016 was $20.42 to $46.19 (2015 – $19.88 to $42.71).

Share Unit Plans

The Company has deferred share unit ("DSU") and performance share unit ("PSU") plans. The DSU and PSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period.

Deferred Share Unit Plans

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, referred to as the Dividend Reinvestment Plan ("DRIP"), the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price during the ten trading days ending on the tenth trading day prior to the payment date.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2016 is presented in the following table:

	Employee DSU	Weighted average grant date fair value	Director DSU	Weighted average grant date fair value
Outstanding as at December 31, 2015	606,646	$ 26.27	362,750	$ 31.36
Granted including DRIP	74,855	37.60	69,429	43.67
Exercised	(570)	46.58	(36,381)	27.42
Outstanding and exercisable as at December 31, 2016	**680,931**	**$ 27.50**	**395,798**	**$ 33.88**

Compensation cost recognized for employee and director DSU for the year ended December 31, 2016 was $8 million (2015 – $8 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2016 were $3 million (2015 – $3 million); $nil was offset with regulatory assets and regulatory liabilities (2015 – $1 million).

Performance Share Unit Plan

Under the PSU plan, executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles. PSUs are granted based on the average of Emera's stock closing price for the 50 trading days prior to a given calculation date. Dividend equivalents are awarded and are used to purchase additional PSUs, also referred to as DRIP. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, disability or death.

A summary of the activity related to employee PSUs for the year ended December 31, 2016 is presented in the following table:

	Employee PSUs	Weighted average grant date fair value	Aggregate intrinsic value
Outstanding as at December 31, 2015	497,496	$ 34.50	$ 21.5
Granted including DRIP	280,950	40.60	
Exercised	(208,999)	34.39	
Forfeited	(8,567)	37.54	
Outstanding as at December 31, 2016	**560,880**	**$ 37.55**	**$ 25.5**

Compensation cost recognized for the PSU plan for the year ended December 31, 2016 was $11 million (2015 – $10 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2016 were $4 million (2015 – $3 million).

33. Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is accounted for using the equity method.

For the years ended December 31, 2016 and 2015, the Company has identified the following material VIEs:

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. In Q2 2014, when the critical milestones were achieved, Nalcor Energy was deemed the beneficiary of the asset for financial reporting purposes as they have authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link Project. Thus, Emera began recording the Maritime Link Project as an equity investment.

BLPC has established a Self-Insurance Fund primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as an "Investment securities", "Restricted cash" and "Regulatory liabilities".

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**December 31, 2016**		December 31, 2015	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 315**	**$ 577**	$ 188	$ 1,007

34. Comparative Information

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

35. Subsequent Events

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 10, 2017, the date the financial statements were issued.

36. Supplemental Financial Information

On June 16, 2016, Emera US Finance LP, (in such capacity, the "Issuer"), issued $3.25 billion USD senior unsecured notes ("U.S. Notes"). The U.S. Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera (in such capacity, the "Parent Company") and EUSHI (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP.

The following consolidated financial statements present the results of operations, financial position and cash flows of the Parent Company, Subsidiary Issuer, Guarantor Subsidiaries and all other Non-guarantor Subsidiaries independently and on a consolidated basis.

Our guarantors were not determined using geographic, service line or other similar criteria, and as a result, the "Parent", "Subsidiary Issuer", "Guarantor Subsidiaries" and "Non-guarantor Subsidiaries" columns each include portions of our domestic and international operations. Accordingly, this basis of presentation is not intended to present our financial condition, results of operations or cash flows for any purpose other than to comply with the specific requirements for guarantor reporting.

Consolidated Statements of Income

Emera Incorporated

For the						Year ended December 31, 2016
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues						
Regulated electric	$ —	$ —	$ 1,665	$ 1,774	$ (2)	**$ 3,437**
Regulated gas	—	—	451	48	—	**499**
Non-regulated	—	—	378	(4)	(33)	**341**
Total operating revenues	—	—	2,494	1,818	(35)	**4,277**
Operating expenses						
Regulated fuel for generation and purchased power	—	—	560	662	—	**1,222**
Regulated cost of natural gas	—	—	177	—	—	**177**
Regulated fuel adjustment mechanism and fixed cost deferrals	—	—	—	61	—	**61**
Non-regulated fuel for generation and purchased power	—	—	261	56	(4)	**313**
Non-regulated direct costs	—	—	—	52	(23)	**29**
Operating, maintenance and general	37	—	647	461	(8)	**1,137**
Provincial, state and municipal taxes	—	—	152	43	—	**195**
Depreciation and amortization	2	—	330	256	—	**588**
Total operating expenses	39	—	2,127	1,591	(35)	**3,722**
Income (loss) from operations	(39)	—	367	227	—	**555**
Income (loss) from equity investments in subsidiaries	150	—	—	—	(150)	**—**
Income from equity investments	18	—	—	82	—	**100**
Intercompany income (expenses), net	203	101	(107)	(151)	(46)	**—**
Other income (expenses), net	135	—	24	15	—	**174**
Interest expense, net	226	85	127	147	—	**585**
Income (loss) before provision for income taxes	241	16	157	26	(196)	**244**
Income tax expense (recovery)	(14)	7	48	(63)	—	**(22)**
Net income (loss)	255	9	109	89	(196)	**266**
Non-controlling interest in subsidiaries	—	—	—	7	4	**11**
Net income (loss) of Emera Incorporated	255	9	109	82	(200)	**255**
Preferred stock dividends	28	—	31	19	(50)	**28**
Net income (loss) attributable to common shareholders	$ 227	$ 9	$ 78	$ 63	$ (150)	**$ 227**
Comprehensive income (loss) of Emera Incorporated	$ 228	$ 19	$ 205	$ 59	$ (283)	**$ 228**

Consolidated Statements of Income

Emera Incorporated

For the						Year ended December 31, 2015
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Regulated electric	$ —	$ —	$ 283	$ 1,860	$ (2)	$ 2,141
Regulated gas	—	—	—	52	—	52
Non-regulated	—	—	419	219	(42)	596
Total operating revenues	—	—	702	2,131	(44)	2,789
Operating expenses						
Regulated fuel for generation and purchased power	—	—	70	745	—	815
Regulated fuel adjustment mechanism and fixed cost deferrals	—	—	—	42	—	42
Non-regulated fuel for generation and purchased power	—	—	277	64	(5)	336
Non-regulated direct costs	—	—	—	49	(30)	19
Operating, maintenance and general	54	—	148	472	(8)	666
Provincial, state and municipal taxes	—	—	21	42	—	63
Depreciation and amortization	1	—	79	260	—	340
Total operating expenses	55	—	595	1,674	(43)	2,281
Income (loss) from operations	(55)	—	107	457	(1)	508
Income (loss) from equity investments in subsidiaries	270	—	—	—	(270)	—
Income from equity investments	37	—	5	66	—	108
Intercompany income (expenses), net	156	—	—	8	(164)	—
Other income (expenses), net	91	—	21	29	—	141
Interest expense, net	46	—	28	272	(134)	212
Income (loss) before provision for income taxes	453	—	105	288	(301)	545
Income tax expense (recovery)	25	—	35	33	—	93
Net income (loss)	428	—	70	255	(301)	452
Non-controlling interest in subsidiaries	—	—	—	13	12	25
Net income (loss) of Emera Incorporated	428	—	70	242	(313)	427
Preferred stock dividends	30	—	15	26	(41)	30
Net income (loss) attributable to common shareholders	$ 398	$ —	$ 55	$ 216	$ (272)	$ 397
Comprehensive income (loss) of Emera Incorporated	$ 911	$ —	$ 303	$ 452	$ (755)	$ 911

Consolidated Balance Sheets

Emera Incorporated

As at						December 31, 2016
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Assets						
Current assets						
Cash and cash equivalents	$ 200	$ 28	$ 48	$ 128	$ —	**$ 404**
Restricted cash	—	—	1	86	—	**87**
Receivables, net	1	—	429	584	—	**1,014**
Intercompany receivables	57	9	11	569	(646)	**—**
Income taxes receivable	—	—	5	28	—	**33**
Inventory	—	—	273	199	—	**472**
Derivative instruments	13	—	33	112	(13)	**145**
Regulatory assets	—	—	54	26	—	**80**
Prepayments and other current assets	2	—	44	230	—	**276**
Total current assets	273	37	898	1,962	(659)	**2,511**
Property, plant and equipment, net of accumulated depreciation	14	—	12,724	4,552	—	**17,290**
Other assets						
Income taxes receivable	—	—	—	48	—	**48**
Deferred income taxes	31	—	18	114	(38)	**125**
Derivative instruments	12	—	2	129	(12)	**131**
Pension and post-retirement asset	—	—	—	9	—	**9**
Regulatory assets	—	—	647	595	—	**1,242**
Net investment in direct financing lease	—	—	13	475	—	**488**
Investments in subsidiaries accounted for using the equity method	8,349	—	—	—	(8,349)	**—**
Investments subject to significant influence	5	—	13	929	—	**947**
Investment securities	—	—	—	48	—	**48**
Goodwill	—	—	6,110	103	—	**6,213**
Intercompany notes receivable	1,341	4,558	16	589	(6,504)	**—**
Other investments – intercompany	—	—	—	2,270	(2,270)	**—**
Other long-term assets	33	—	85	70	(19)	**169**
Total other assets	9,771	4,558	6,904	5,379	(17,192)	**9,420**
Total assets	$ 10,058	$ 4,595	$ 20,526	$ 11,893	$ (17,851)	**$ 29,221**

Consolidated Balance Sheets (continued)

Emera Incorporated

As at						December 31, 2016
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Liabilities and Equity						
Current liabilities						
Short-term debt	$ —	$ —	$ 948	$ 13	$ —	**$ 961**
Current portion of long-term debt	—	—	436	40	—	**476**
Accounts payable	6	—	756	480	—	**1,242**
Intercompany payable	534	6	81	25	(646)	**—**
Income taxes payable	—	6	—	13	—	**19**
Derivative instruments	14	—	10	314	(13)	**325**
Regulatory liabilities	—	—	225	137	—	**362**
Pension and post-retirement liabilities	—	—	51	7	—	**58**
Other current liabilities	54	7	79	141	—	**281**
Total current liabilities	608	19	2,586	1,170	(659)	**3,724**
Long-term liabilities						
Long-term debt	2,338	4,314	4,687	2,929	—	**14,268**
Intercompany long-term debt	366	—	4,778	1,357	(6,501)	**—**
Deferred income taxes	—	1	1,193	516	(38)	**1,672**
Convertible debentures	8	—	—	—	—	**8**
Derivative instruments	12	—	—	150	(12)	**150**
Regulatory liabilities	—	—	973	304	—	**1,277**
Asset retirement obligations	—	—	61	109	—	**170**
Pension and post-retirement liabilities	17	—	433	219	—	**669**
Other long-term liabilities	5	—	213	268	(19)	**467**
Total long-term liabilities	2,746	4,315	12,338	5,852	(6,570)	**18,681**
Equity						
Common stock	4,738	242	4,177	3,997	(8,416)	**4,738**
Cumulative preferred stock	709	—	620	271	(891)	**709**
Contributed surplus	75	—	45	106	(151)	**75**
Accumulated other comprehensive income (loss)	106	10	340	(191)	(159)	**106**
Retained earnings	1,076	9	420	610	(1,039)	**1,076**
Total Emera Incorporated equity	6,704	261	5,602	4,793	(10,656)	**6,704**
Non-controlling interest in subsidiaries	—	—	—	78	34	**112**
Total equity	6,704	261	5,602	4,871	(10,622)	**6,816**
Total liabilities and equity	$ 10,058	$ 4,595	$ 20,526	$ 11,893	$ (17,851)	**$ 29,221**

Consolidated Balance Sheets

Emera Incorporated

As at						December 31, 2015
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$ —	$ —	$ 19	$ 1,068	$ (14)	$ 1,073
Restricted cash	—	—	1	18	—	19
Receivables, net	2	—	70	506	—	578
Intercompany receivable	102	—	51	95	(248)	—
Income taxes receivable	—	—	9	3	—	12
Inventory	—	—	48	266	—	314
Derivative instruments	109	—	46	112	(17)	250
Regulatory assets	—	—	17	77	—	94
Prepayments and other current assets	9	—	4	243	—	256
Total current assets	222	—	265	2,388	(279)	2,596
Property, plant and equipment, net of accumulated depreciation	15	—	2,035	4,419	—	6,469
Other assets						
Income taxes receivable	—	—	—	49	—	49
Deferred income taxes	—	—	47	19	(34)	32
Derivative instruments	35	—	—	167	(34)	168
Pension and post-retirement assets	—	—	—	9	—	9
Regulatory assets	—	—	100	505	—	605
Net investment in direct financing lease	—	—	—	480	—	480
Investments in subsidiaries accounted for using the equity method	6,042	—	—	—	(6,042)	—
Investments subject to significant influence	509	—	12	624	—	1,145
Investment securities	—	—	—	116	—	116
Goodwill	—	—	158	106	—	264
Intercompany notes receivable	3,051	—	—	2,754	(5,805)	—
Other investments – intercompany	—	—	—	98	(98)	—
Other long-term assets	16	—	13	77	—	106
Total other assets	9,653	—	330	5,004	(12,013)	2,974
Total assets	$ 9,890	$ —	$ 2,630	$ 11,811	$ (12,292)	$ 12,039

Emera Incorporated

As at						December 31, 2015
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
Liabilities and Equity						
Current liabilities						
Short-term debt	$ 14	$ —	$ —	$ 16	$ (14)	$ 16
Current portion of long-term debt	250	—	6	18	—	274
Accounts payable	17	—	76	301	—	394
Income taxes payable	—	—	—	8	—	8
Intercompany payable	52	—	92	77	(221)	—
Derivative instruments	17	—	36	313	(17)	349
Regulatory liabilities	—	—	10	102	—	112
Pension and post-retirement liabilities	—	—	—	7	—	7
Other current liabilities	51	—	24	132	—	207
Total current liabilities	401	—	244	974	(252)	1,367
Long-term liabilities						
Long-term debt	464	—	389	2,882	—	3,735
Intercompany long-term debt	2,631	—	120	3,072	(5,823)	—
Deferred income taxes	3	—	343	450	(34)	762
Convertible debentures (represented by instalment receipts)	2,139	—	—	(1,458)	—	681
Derivative instruments	34	—	—	96	(34)	96
Regulatory liabilities	—	—	12	341	—	353
Asset retirement obligations	—	—	—	109	—	109
Pension and post-retirement liabilities	13	—	93	197	—	303
Other long-term liabilities	5	—	61	233	—	299
Total long-term liabilities	5,289	—	1,018	5,922	(5,891)	6,338
Equity						
Common stock	2,157	—	312	3,829	(4,141)	2,157
Cumulative preferred stock	709	—	425	271	(696)	709
Contributed surplus	29	—	45	133	(178)	29
Accumulated other comprehensive income (loss)	137	—	245	(169)	(76)	137
Retained earnings	1,168	—	341	751	(1,092)	1,168
Total Emera Incorporated equity	4,200	—	1,368	4,815	(6,183)	4,200
Non-controlling interest in subsidiaries	—	—	—	100	34	134
Total equity	4,200	—	1,368	4,915	(6,149)	4,334
Total liabilities and equity	$ 9,890	$ —	$ 2,630	$ 11,811	$ (12,292)	$ 12,039

Consolidated Statements of Cash Flows

Emera Incorporated

For the						Year ended December 31, 2016
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Net cash provided by (used in) by operating activities	$ 265	$ 29	$ 481	$ 107	$ 171	**$ 1,053**
Investing activities						
Acquisitions, net of cash acquired	—	—	(8,409)	—	—	**(8,409)**
Additions to property, plant and equipment	(2)	—	(633)	(396)	—	**(1,031)**
Net purchase of investments subject to significant influence, inclusive of acquisition costs	—	—	—	(276)	—	**(276)**
Net proceeds on sale of investment subject to significant influence and held-for-trading common shares	665	—	—	—	—	**665**
Other intercompany investing activities	(2,348)	(4,416)	(18)	(2,397)	9,179	**—**
Other investing activities	—	—	(42)	(12)	—	**(54)**
Net cash provided by (used in) investing activities	(1,685)	(4,416)	(9,102)	(3,081)	9,179	**(9,105)**
Financing activities						
Change in short-term debt, net	(14)	—	122	(4)	14	**118**
Proceeds from long-term debt, net of issuance costs	2,037	4,187	4,516	764	(5,081)	**6,423**
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs	(44)	—	—	1,457	—	**1,413**
Retirement of long-term debt	(250)	—	(6)	(36)	19	**(273)**
Net borrowings (repayments) under committed credit facilities	(210)	—	—	(99)	(6)	**(315)**
Issuance of common stock, net of issuance costs	354	242	3,865	95	(4,202)	**354**
Issuance of preferred stock, net of issuance costs	—	—	195	—	(195)	**—**
Dividends on common stock	(221)	—	—	(254)	254	**(221)**
Dividends on preferred stock	(28)	—	(31)	(18)	49	**(28)**
Dividends paid by subsidiaries to non-controlling interest	—	—	—	(2)	(3)	**(5)**
Other financing activities	—	—	(18)	185	(185)	**(18)**
Net cash provided by (used in) financing activities	1,624	4,429	8,643	2,088	(9,336)	**7,448**
Effect of exchange rate changes on cash and cash equivalents	(4)	(14)	7	(54)	—	**(65)**
Net increase (decrease) in cash and cash equivalents	200	28	29	(940)	14	**(669)**
Cash and cash equivalents, beginning of period	—	—	19	1,068	(14)	**1,073**
Cash and cash equivalents, end of period	$ 200	$ 28	$ 48	$ 128	$ —	**$ 404**

Consolidated Statements of Cash Flows

Emera Incorporated

For the						Year ended December 31, 2015
millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 291	$ —	$ 190	$ 364	$ (171)	$ 674
Investing activities						
Additions to property, plant and equipment	(7)	—	(66)	(354)	—	(427)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	(1)	—	(3)	(132)	—	(136)
Proceeds on sale of investment subject to significant influence	—	—	282	—	—	282
Other intercompany investing activities	(2,453)	—	—	(29)	2,482	—
Other investing activities	(751)	—	(10)	(413)	1,331	157
Net cash provided by (used in) investing activities	(3,212)	—	203	(928)	3,813	(124)
Financing activities						
Change in short-term debt, net	4	—	—	(262)	(4)	(262)
Proceeds from long-term debt, net of issuance costs	—	—	29	1,465	(1,048)	446
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs	2,138	—	—	(1,457)	—	681
Retirement of long-term debt	—	—	(420)	(372)	702	(90)
Net borrowings (repayments) under committed credit facilities	(39)	—	(9)	(153)	—	(201)
Issuance of common stock, net of issuance costs	9	—	—	2,390	(2,390)	9
Issuance of preferred stock, net of issuance costs	—	—	—	6	(6)	—
Dividends on common stock	(162)	—	—	(162)	162	(162)
Dividends on preferred stock	(30)	—	(15)	(25)	40	(30)
Dividends paid by subsidiaries to non-controlling interest	—	—	—	(3)	(11)	(14)
Other financing activities	1,001	—	(11)	(55)	(1,091)	(156)
Net cash provided by (used in) financing activities	2,921	—	(426)	1,372	(3,646)	221
Effect of exchange rate changes on cash and cash equivalents	—	—	14	67	—	81
Net increase (decrease) in cash and cash equivalents	—	—	(19)	875	(4)	852
Cash and cash equivalents, beginning of period	—	—	38	193	(10)	221
Cash and cash equivalents, end of period	$ —	$ —	$ 19	$ 1,068	$ (14)	$ 1,073

Emera Leadership & Board

EMERA LEADERSHIP

Christopher Huskilson
President and
Chief Executive Officer,
Emera Inc.

Rob Bennett
President and
Chief Executive Officer,
Emera US Holdings Inc.

Scott Balfour
Chief Operating Officer,
Emera Inc.

Greg Blunden
Chief Financial Officer,
Emera Inc.

Nancy Tower
Chief Corporate
Development Officer,
Emera Inc.

Michael Roberts
Chief Human Resources Officer,
Emera Inc.

Bruce Marchand
Chief Legal and
Compliance Officer,
Emera Inc.

Robert Hanf
Executive Vice President,
Stakeholder Relations and
Regulatory Affairs,
Emera Inc.

Sarah MacDonald
President, TECO Services, Inc.

Dan Muldoon
Executive Vice President,
Major Renewable
and Alternative Energy,
Emera Inc.

Wayne O'Connor
Executive Vice-President,
Corporate Strategy and
Planning,
Emera Inc.

Judy Steele
President and
Chief Operating Officer,
Emera Energy

Alan Richardson
President and
Chief Operating Officer,
Emera Maine

Rick Janega
President and
Chief Executive Officer,
Emera Newfoundland
and Labrador

Karen Hutt
President and
Chief Executive Officer,
Nova Scotia Power

Ryan Shell
President,
New Mexico Gas Company

Gordon Gillette
President and
Chief Executive Officer,
Tampa Electric Company

Archie Collins
President and
Chief Executive Officer,
Grand Bahama Power Company;
Chief Operating Officer,
Emera (Caribbean) Inc.

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Former Executive Vice President,
Corporate & Legal Affairs,
Talisman Energy Inc.,
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Sylvia Chrominska
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Global Human Resources
and Communications,
The Bank of Nova Scotia,
Toronto, Ontario

Henry Demone
Chairman,
High Liner Foods,
Lunenburg, Nova Scotia

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Calgary, Alberta

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Lunenburg, Nova Scotia

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Emera Inc.,
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Westmount, Quebec

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Allstream Inc.,
Mahone Bay, Nova Scotia

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Former Chair of the Board and
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Former President and
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TECO Energy, Inc.

Andrea Rosen
Former Vice Chair,
TD Bank Financial Group
and President,
TD Canada Trust,
Toronto, Ontario

Richard Sergel
Former President and
Chief Executive Officer,
North American Electric
Reliability Corporation
(NERC),
Wellesley, Massachusetts

Shareholder Information

SHAREHOLDER INFORMATION

For general inquiries about our Company,
please contact our corporate office:

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Information regarding Company news and initiatives, including our 2016 Annual Report, is also available at our website:
www.emera.com

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Annual Meeting

The Annual Meeting is scheduled to be held May 12, 2017 at 2:00 p.m. (Atlantic Time) at Ondaatje Hall in the Marion McCain Arts and Social Sciences Building at Dalhousie University, 6134 University Ave., Halifax, Nova Scotia.

This Annual Report contains forward-looking information. Actual future results may differ materially. Additional financial and operational information is filed electronically with various securities commissions in Canada through the System for Electronic Document Analysis and Retrieval (SEDAR).

Share Listings

Toronto Stock Exchange (TSX)
Common Shares: EMA
Preferred Shares: EMA.PR.A, EMA.PR.B, EMA.PR.C, EMA.PR.E and EMA.PR.F
Instalment Receipts: EMA.IR
Barbados Stock Exchange (BSE)
Depositary Receipts: EMABDR

Shares Outstanding

Common Shares: 210,024,388 (as of December 31, 2016)

Dividends Paid in 2016

Emera Inc., paid Common Share dividends of $0.4750 per Common Share in Q1 and Q2 and $0.5225 in Q3 and Q4, for an effective annual Common Share dividend rate of $1.9950 per Common Share.

Dividend Payments in 2017

Subject to approval by the Board of Directors, dividends for Emera Inc. are payable on or about the 15th of February, May, August and November. A first quarter Common Share dividend of $0.5225 per Common Share and a Series A First Preferred Share dividend of $0.1597, Series B First Preferred Share dividend of $0.1473, Series C First Preferred Share dividend of $0.25625 per share, Series E First Preferred Share dividend of $0.28125, Series F First Preferred Share dividend of $0.265625 was declared and paid on February 15, 2017.

Dividend Reinvestment and Share Purchase Plan

Emera's Dividend Reinvestment and Share Purchase Plan is available to shareholders resident in Canada. The plan provides shareholders with a convenient and economical means of acquiring additional Common Shares through the reinvestment of dividends at a five per cent discount. Plan participants may also contribute cash payments of up to $5,000 per quarter. Participants of the plan pay no commissions, service charges or brokerage fees for shares purchased under the plan. Please contact Investor Services if you have questions or wish to receive an enrollment form.

Direct Deposit Service

Shareholders may have dividends deposited directly into accounts held at financial institutions that are members of the Canadian Payments Association. To arrange this service, please contact Investor Services.

Quarterly Earnings

Quarterly earnings are expected to be announced May, August and November 2017. Year-end results for 2016 were released in February 2017.

Printed on Rolland Opaque, an FSC® Mix certified paper, which contains 30% de-inked post-consumer fibre and is manufactured in Canada with biogas (an alternative green energy source that reduces greenhouse gas emissions that cause global warming).

Emera

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